Citizens Opposed to Oil Pollution, Save Union County, and the Sierra Club

Comments on Hyperion Energy Center's Prevention of Significant Deterioration Pre-Construction Air Quality Permit Application and Draft Permit #28.0701-PSD

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I. Introduction And Interests Of Organizations As Commentors

Save Union County, LLC ("Save Union County"), Citizens Opposed to Oil Pollution ("C.O.O.P.") and the Sierra Club (collectively "Commentors") oppose the Hyperion Energy Center's Draft Prevention of Significant Deterioration Air Quality Preconstruction Permit, issued by the Department of Environment and Natural Resources ("DENR") on September 11, 2008 ("Draft Permit") and request that DENR decline to issue a final permit at this time.

Save Union County is a grassroots organization of over 1,500 members throughout the tri-state area who are opposed to the HEC, which Save Union County believes will have serious and life-threatening consequences to the environment and the present quality of life of its members. Save Union County firmly supports the development of renewable sustainable energy and economic development that is appropriate for and commensurate with our present infrastructure and socio-economic systems. Save Union County has many members who own and rent land near the proposed site for the HEC, many within 2-3 miles of the proposed location. Many of Save Union County's members use their land for farming. Save Union County members regularly enjoy fishing, hiking, and other recreational activities at Brule Creek, which runs through the proposed location of the HEC.

C.O.O.P. is a cooperative effort of people of all political affiliations, farmers, city dwellers, business leaders, conservationists, and environmentalists who question the logic of locating an oil refinery in South Dakota. As we move forward into the next century, C.O.O.P. would like to see South Dakota lead the way in renewable and alternative energy production and not cling to old polluting technologies like oil. C.O.O.P has approximately 60 members who live in close proximity to the proposed location of the Hyperion Energy Center ("HEC"). Many C.O.O.P. members own or rent land within a few miles of the proposed location.

The Sierra Club is a national nonprofit organization of approximately 1.3 million members and supporters dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. The Sierra Club's concerns encompass the goal of achieving a more efficient use of current energy resources, conservation of precious natural resources, development of clean, renewable energy resources, protection of public health and the reduction of greenhouse gas emissions that may result in climate change and variability. The Club's particular interest in this case and the issues which the case concerns stem from the impact of the proposed HEC on each of the concerns just mentioned. In particular, there is concern over the health impacts on individual members of the South Dakota Chapter and its Living River Group, as well as a threatened reduction in the overall quality of life of its members, including but not limited to recreation, economic, and aesthetic interests. The South Dakota Chapter of the Sierra Club has approximately 896 members, 96 of whom make up the Chapter's Living River Group. The Living River Group is based in the town of Vermillion, South Dakota, located less than 10 miles from the site of the proposed HEC.

As noted by the Seventh Circuit in *Sierra Club v. Franklin County Power of Illinois, LLC*, No. 06-4045, 2008 WL 4693519, at *3 (7th Cir. Oct. 27, 2008), "an organization has standing to sue if (1) at least one of its members would otherwise have standing; (2) the interests at stake in the litigation are germane to the organization's purpose; and (3) neither the claim asserted nor the relief requested requires an individual member's participation in the lawsuit." As shown above, Save Union County, C.O.O.P. and Sierra Club meet those requirements.

II. Legal Background

The federal Clean Air Act ("CAA" or "the Act") was written "to protect and enhance the quality of the nation's air so as to promote the public health and welfare and the productive capacity of its population."[1] As directed by Section 109 of the Act, 42 U.S.C. § 7409, the U.S. Environmental Protection Agency ("EPA") has established National Ambient Air Quality Standards ("NAAQS") to protect human health and the environment for seven "criteria pollutants," including sulfur dioxide, nitrogen oxides, particulate matter, carbon monoxide, and ozone.[2] Under section 107(d) of the Act, 42 U.S.C. § 7407(d), each state must designate those areas in its territory where the air quality is better or worse than the NAAQS for each criteria pollutant, or where the air quality cannot be classified because of insufficient data. An area that meets the NAAQS for a particular criteria pollutant is an "attainment" area for that pollutant. Under section 110(a) of the Act, 42 U.S.C. § 7410(a), states are responsible for implementing many of the regulatory requirements of the Act, including provisions of the Prevention of Significant Deterioration ("PSD") program, through State Implementation Plans ("SIPs"). SIP provisions must satisfy the requirements of the Act before they are approved by EPA.[3]

Part C of subchapter I of the Act, 42 U.S.C. §§ 7470-7492 (the "PSD program"), sets out requirements for the prevention of significant deterioration of air quality in areas designated as attainment areas. The purpose of these requirements is to protect public health and welfare, to ensure that economic growth will occur in a manner consistent with the preservation of existing clean air resources, and to assure that any decision to permit increased air pollution is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decision making process.[4] Section 165(a) of the Act, 42 U.S.C. § 7475(a), prohibits the construction and operation of a "major emitting facility" in an attainment area unless a permit has been issued that contains emissions limitations that comply with the requirements of section 165.

Section 165 includes several requirements. First, the owner or operator of the facility must show that "emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of (A) maximum allowable increase...for any pollutant in any area to which this part applies more than one time per year; (B) [NAAQS] in any air quality control region; or (C) any other applicable emission standard or standard of performance under

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[1] 42 U.S.C. § 7401(b)(1) (2008).

[2] 40 C.F.R. pt. 50 (2008).

[3] *See* 42 U.S.C. § 7410(k); *see also* 40 C.F.R. § 51.166 (PSD); 40 C.F.R. § 51.165 (NNSR).

[4] 42 U.S.C. § 7470.

this chapter."[5] Second, the facility must install the best available control technology ("BACT") for each pollutant subject to regulation under the Act that is emitted from the facility.[6] Third, the facility must analyze "any air quality impacts projected for the area as a result of growth associated with such facility."[7] Fourth, if the owner or operater of the proposed facility is notified that emissions from the proposed facility may "cause or contribute to a change in the air quality in [a Class I PSD] area, that owner or operator must demonstrate that "emissions of particulate matter and sulfur dioxide will not cause or contribute to concentrations which exceed the maximum allowable increase for a class I area."[8] Finally, the owner or operator of the proposed facility must agree to "conduct such monitoring as may be necessary to determine the effect which emissions from any such facility may have...on air quality in any area which may be affected by emissions from such source." [9] South Dakota's federally approved SIP implements, with minimal exception, the PSD provisions of the Act in South Dakota.[10]

III. <u>The Draft Permit Should Not Have Been Issued Without a Prior Environmental Impact Statement</u>

The HEC, if it proceeds, will be, by far, the largest refinery and electric generating plant ever built in South Dakota and one of the largest in the United States. As planned, the HEC will be massive, including a 400,000 barrel per day refinery and an approximately 200 MW integrated gasification combined cycle power plant. The HEC will emit, without question, serious air pollutants.

The HEC will not only pollute the air, but it will also adversely impact neighboring waters, due to the water needs and wastewater discharges of the refinery and generating plant. In addition, there will be other significant wastes arising from or generated during the Center's construction and operation, including those arising from (i) the plan to transport tar sands crude by pipeline to the Center from Canada, (ii) potential emissions from flares, and (iii) waste disposal activities. The Center will emit numerous hazardous air pollutants as well, including highly toxic mercury. Without question, the HEC has the potential to do more environmental damage than any other industrial project constructed in South Dakota during the past 100 years. Therefore, the DENR should require an environmental impact statement ("EIS") for the HEC before any component of the project is approved.

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[5] 42 U.S.C. § 7475(a)(3).

[6] 42 U.S.C. § 7475(a)(4); *see also* 40 C.F.R. § 52.21(b)(12).

[7] 42 U.S.C. § 7475(a)(6).

[8] 42 U.S.C. § 7475(d)(2)(C)(i); *see also* 40 C.F.R. § 52.21(b)(29).

[9] 42 U.S.C. § 7475(a)(7).

[10] *See* S.D. Admin. R. 74:36:09:02; Approval and Promulgation of Air Quality Implementation Plans; South Dakota, 72 Fed. Reg. 72,617 (Dec. 21, 2007).

The very "purpose" of an EIS under South Dakota law "is to provide detailed information about the effect which a proposed action is likely to have upon the environment, to list ways in which any adverse effects of the action might be minimized, and to suggest alternatives to the action."[11] This purpose mirrors that under the analogous federal environmental law known as the National Environmental Policy Act ("NEPA"). In fact, the South Dakota legislature acknowledged that the South Dakota EIS requirements are modeled after NEPA by directly referencing NEPA requirements in the South Dakota EIS law.[12] NEPA was passed to ensure that decision-making agencies "will have available, and will carefully consider, detailed information concerning significant environmental impact [and] guarantee [ ] that the relevant information will be made available to the larger [public] audience."[13] "NEPA expresses a Congressional determination that procrastination on environmental concerns is no longer acceptable."[14]

The strong public policy goals for conducting an EIS are also evident in the South Dakota Environmental Protection Act of 1973 ("SDEPA").[15] As part of any DENR permitting proceedings, such as the Application, the SDEPA requires DENR to determine "any alleged pollution, impairment, or destruction of the air, water, or other natural resources or the public trust."[16] If a proposed project will have detrimental effects on the air, water, or other natural resources of South Dakota, and there is "a feasible and prudent alternative," the SDEPA states that such a project shall not be authorized.[17] In order to comply with the SDEPA, DENR must determine the HEC's potential for harming the air, water, or other natural resources of South Dakota <u>and</u> determine whether there are any feasible and prudent alternatives to the project proposed by the Applicant. Conducting an EIS is the most logical method DENR can implement in order to make such a determination and thus comply with the SDEPA.

If there were ever a project in South Dakota requiring an environmental impact statement, this is it. Indeed, if DENR will not require an EIS in this case, then it is difficult to imagine a situation where DENR would ever require one. The purpose of an EIS, under either federal or state law, is to provide a full analysis and assessment of a proposed project <u>at the outset</u>, before there is an irreversible and irretrievable commitment of resources.[18] In other words, an EIS must

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[11] *S.D. Codified Laws § 34A-9-4 (2008).*

[12] *S.D. Codified Laws § 34A-9-7.*

[13] *Idaho Sporting Cong. v. Thomas*, 137 F.3d 1146, 1149 (9th Cir. 1998) (quoting *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 349 (1989)); *see also* 40 C.F.R. § 1500.1(b) (finding that environmental information must be provided "<u>before</u> decisions are made and before actions are taken" (emphasis added)).

[14] *Found. for N. Am. Wild Sheep v. U.S. Dep't of Agric.*, 681 F.2d 1172, 1181 (9th Cir. 1982).

[15] *S.D. Codified Laws §§ 34A-10-1 et seq.*

[16] *S.D. Codified Laws § 34A-10-8.*

[17] *Id.*

[18] *S.D. Codified Laws § 34A-9-4.*

be undertaken before decisions are made concerning the issuance of licenses, so that there is not an irreversible or irretrievable commitment of resources to a project which renders the decision to proceed with a project inevitable or a fait accompli. Moreover, the EIS must "rigorously explore and objectively evaluate all reasonable alternatives,"[19] because the analysis of alternatives is the "heart" of the EIS.[20] In other words, environmental impact analysis must consider the alternatives to a proposed project, "to the fullest extent possible."[21] This review of alternatives should include, but not be limited to: (i) rigorously exploring and objectively evaluating all reasonable alternatives to the project in detail, to allow for an evaluation of the comparative merits of alternatives; (ii) an assessment of reasonable alternatives including those not within the jurisdiction of the lead agency; and (iii) an evaluation of the alternative of no action at all, *i.e.*, not proceeding with the project at all.[22]

Although there will be at numerous individual regulatory reviews of the HEC in the form of permit applications and otherwise, no individual permit or regulatory reviews will achieve the goals of an environmental impact analysis. To the contrary, the anticipated regulatory review of the HEC will not:

- evaluate the environmental impacts of the HEC to the fullest extent possible before an irretrievable and irreversible commitment of resources is made;
- provide a full upfront analysis of all environmental impacts from the HEC upon the air, water, and soils -- both in South Dakota and also in downwind states;
- rigorously explore and objectively evaluate all reasonable alternatives to the HEC; or
- evaluate the cumulative environmental impacts from the construction and operation of the HEC.

Consequently, without an environmental impact analysis undertaken prior to the commencement of these individual regulatory reviews, DENR will not be able to make the most informed decisions and the public's right to know will be irrevocably compromised. Because there are numerous individual regulatory reviews that will take place for the HEC, interagency cooperation is necessary to fully understand the impacts of such a large project. Interagency cooperation is anticipated by the Clean Air Act regulations that are currently under consideration in Hyperion's Prevention of Significant Deterioration Air Quality Preconstruction Permit ("the Application"). These regulations state that when an EIS is being prepared for a proposed source, the review of the PSD permit application "shall be coordinated with the broad environmental

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[19] 40 C.F.R. § 1502.14(a).

[20] *Id. See also Ilio'ulaokalani Coal. v. Rumsfeld*, 464 F.3d 1083, 1095 (9th Cir. 2006); *NRDC v. U.S. Forest Serv.*, 421 F.3d 797, 813 (9th Cir. 2005).

[21] 42 U.S.C. § 4332(2)(c)(i); *see also* 40 C.F.R. § 1500.2.

[22] *See* 40 C.F.R. § 1502.14.

reviews under [NEPA] to the maximum extent feasible and reasonable."[23] The only way to gain a full understanding of the environmental impacts of the HEC is if the numerous agencies that will be conducting individual regulatory reviews of the proposed project coordinate their efforts to conduct a comprehensive environmental review.

Finally, the HEC, in its Petition for the Issuance of the Application, has failed even to address numerous key issues which should be addressed by DENR in an environmental assessment and impact analysis before the proposed permit can issue. The present DENR permitting process is not holistic and will omit many major and significant parameters from consideration. Among the items not considered or inadequately reviewed are the following:

- Noise;
- Odors;
- Night lightings' effects on birds, insects, and humans;
- There will be no review of Best Management Practices to examine alternative placements of petroleum-bearing pipes within the refinery;
- Placement of pipes carrying crude to the refinery will be considered after the details of plant construction. There is currently no description of how crude will be conveyed to the site;
- There will be no opportunity to discuss water withdrawals (either on or off-site) and water use efficiency in the plant (i.e. water recycling in the plant);
- There will be no opportunity to review energy efficiency on an energy input per product output basis;
- There is no consideration of energy recovery alternatives from process heater waste heat now discharged, including overall site energy efficiency and utilization review;
- Site wide groundwater conservation and control measures;
- Local and regional road traffic issues;
- Regional increased demand for housing and services during project construction, including degradation of local rural roads used for construction;
- Review of potential for rail shipments to disrupt local railroad and highway crossings as well as local farming and business operations;
- Project site wetlands and stream water quality and aquatic habitat alternatives evaluation and ambient water quality impact;

[23] 40 C.F.R. § 52.21(s).

- Project site terrestrial wildlife habitat evaluation;
- Project site stormwater management considerations both during and after construction;
- Evaluation of endangered species impacts from any of the project site's physical elements;
- Project impact mitigation alternatives, both onsite and off;
- Social impact of the refinery on rural area population and local patterns of development, including negative impact on the area's rural character;
- Evaluation and overall systems review of reliance on tar sands development in Canada to support crude availability for the Center;
- Evaluation of physical connectedness elements between the refinery ad input and output pipelines;
- Discussion and layout of proposed refined product pipelines, especially as they relate to public rights-of-way and water resources;
- Disposal of brines and salts contained in crude received by the plant, including consideration of the alternative of deep well disposal for brines and ammonia solutions;
- Discussion of any facility solid waste management units planned;
- Disposition of wastewater treatment sludge, including potential for coking as material recovery;
- Discussion of energy infrastructure protection and security considerations;
- Discussion of flare and relief system alternatives, including visual impacts of flares offsite;
- Effect of facility existence on need for local firefighting services and firefighter training;
- Effect of facility existence on need for public safety and homeland security resources;
- Facility construction and operation impacts on patterns of local and regional skilled labor utilization;
- Review of maximum offsite consequences of a toxic release and/or disposal from the facility;
- Multi-media and process media transfer review on toxicants;

- Review of persistent and bio-accumulative toxicant emissions, such as mercury, with full emission and process characterization and multi-pathway environmental and ecological risk assessment;

- Identification of any invasive or nuisance plant species present at the site, if any, and identify whether construction activities have the potential to cause invasive or nuisance plant species to be brought onsite;

- Review of all irretrievable commitments of natural resources inherent in project development including from source to distribution of refined products;

- Socio-economic impacts on the local and regional neighborhoods relative to social service needs during construction as well as normal operations; or

- Regional impacts on neighboring states that must be evaluated by other states or other parties.

For all of the foregoing reasons, DENR should require an EIS for the proposed HEC prior to issuing any individual environmental permit. The time for an EIS is now. Individual regulatory reviews are no substitute for the full and fair analysis by DENR of the environmental impacts of the HEC. EIS analysis is the "basic national charter for protection of the environment."[24] South Dakota citizens are entitled to no less.

IV. <u>The Application Is Incomplete</u>

A. <u>The State Cannot Have Evaluated If The Facility Will Meet PSD Requirements Without The Information That Is Missing From The Permit Application</u>

Although the Application provides the conclusion of Hyperion Refining, LLC's ("the Applicant") emission calculations, it does not provide any process details or assumptions which underlie the emissions calculations; thus the emissions calculations cannot be verified. The overall discussion is cursory and does not explain how the calculation satisfies the regulatory criteria of defining the emissions under potential to emit criteria - "the maximum capacity of a stationary source to emit a pollutant under its physical and operational design."[25]

First and foremost, no information is provided on the composition of the crude oil that is to be processed in the refinery. The design of the refinery and its emissions depend on the crude composition. Not only is this true for everyday emissions (such as SO_2 or other sulfur compounds, as well as numerous metals) for which it is impossible to determine a mass-balance of the pollutants entering and leaving the refinery, it is also critical for the determination of occasional emissions, which are significant in any refinery. Occasional emissions, whether planned or unplanned, depend on the processing of the crude and its resultant crude-derived products in the refinery. The composition of the crude (including parameters such as its sulfur

[24] 40 C.F.R. § 1500.1(a).

[25] *See* 40 C.F.R §§ 52.21(b)(4), 51.165(a)(1)(iii), 51.166(b)(4); and U.S. EPA, *Limiting Potential To Emit In New Source Permitting*, at 7 (June 13, 1989).

content, its acid content, its metal content and others) will determine the severity of the processing anticipated and therefore the likelihood of occasional emissions. The Application simply does not account for any occasional emissions, even though they are a significant part of routine emissions of any refinery. It is impossible to even begin the determination of occasional emissions without a fundamental understanding of the crude that will be processed in the refinery.

Second, the Application does not provide necessary process details needed for emissions calculation or verification. No process details (i.e., stream flow rates and composition data) are provided for any of the process units. As such, all calculations are unsupported.

Third, for several of the emissions processes, such as the wastewater treatment system or the storage tanks, the Applicant has simply stated that it used an EPA computer model, such as WATER9 or TANKS, and calculated a certain value for emissions. In essence the Applicant says, "we used a specific computer model and here is the result." None of the computer inputs, modeling parameters or model outputs have been provided with the Application. There is no clearly ascertainable basis for the results of the computer modeling in the Application and it would have been impossible for the State to determine if the modeling results accurately reflect the maximum capacity of the source to emit a pollutant under its physical and operational design.

Fourth, the Application provides no information on emissions of NSR-regulated pollutants from flares other than from flare pilot gas combustion. Consequently there is no clearly ascertainable basis for concluding that the emissions estimate represents, "the maximum capacity of the source to emit a pollutant under its physical and operational design."[26]

Fifth, fugitive emissions are a significant component of any refinery emissions. The Applicant's emissions calculations in this regard are simply based on assumed numbers of fugitive components, with no break-out by process unit or area. As such they are completely unverifiable. Additionally, without allocation of specific units or areas, they cannot be spatially allocated in a verifiable manner – leading to improper or invalid modeling impact analyses.

Sixth, much of the information required by the Application forms has been left blank in the Application package. In particular, design details required for air pollution control equipment are left blank. Thus, it is impossible to verify whether or not a given air pollution control equipment will, in fact, achieve its stated goal. Since compliance verification in the proposed permit is weak, as will be discussed later, the combination of an incomplete application coupled with a weak permit is an unacceptable approach to meeting regulatory and legal requirements.

Given such major data omissions and deficiencies, it is impossible to conduct a meaningful review of the information provided. As a simple example, if the State cannot validate the emissions estimates provided by the Applicant, then it cannot determine if appropriate maximum emissions inputs were used in the air quality modeling analyses, risk analyses, etc. If the State cannot evaluate the accuracy of the Applicant's emissions estimates or

[26] 40 C.F.R. § 52.21(a)(4).

air quality impact analyses, then it cannot adequately review the Application or issue the draft permit.

The Environmental Appeals Board ("EAB") has previously concluded that PSD applications, and resulting PSD permits are inappropriate where there is no clearly ascertainable basis for the critical determinations the permit writer must make.

> Thus, in *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121 (EAB 1999), for example, the Board remanded a PSD permit because the permit application contained the conclusion of a BACT analysis but not the underlying analysis - i.e., the "clearly ascertainable basis" for the conclusion - itself. See id. at 134-42.[27]

Here, as in *Knauf* and *Tallmadge*, the Applicant has failed to provide a clearly ascertainable basis for many of the technology, modeling and other decisions necessary for an appropriate PSD permit.

B. The Public Cannot Meaningfully Comment On The Draft Permit Because The Application Is Incomplete[28]

The public cannot provide informed public comment on the Draft Permit for the same reasons listed above.

V. The Application Does Not Fully And Correctly Characterize Emissions Of NSR-Regulated Pollutants And Does Not Provide Enough Information To Verify Emissions Characterizations Of Several NSR-Regulated Pollutants

A. The Application Fails To Fully Characterize Emissions Of Regulated Pollutants From The Facility For A Proper PSD Evaluation

1. *The Application Fails To Provide Adequate Information To Determine If There Are Additional Emissions Units Whose Emissions Must Be Added To The Emissions Calculations Of The Proposed Facility*

In both the Application and the Draft Permit, the extent of the facility boundary, both functionally and spatially, is ill-defined. The application does not provide adequate information to determine if there are additional emissions units, not located within the facility boundaries, whose emissions must be added to the emissions calculations of the proposed facility. Specifically, the Application provides no information on the characterization of or emissions from downstream finished product emissions units such as pumping stations or gasoline bulk

[27] *In Re: Tallmadge Generating Station*, PSD Appeal No. 02-12, at 7 (E.A.B. May 22, 2003).

[28] Informed public participation is one purpose of the PSD program: "The purposes of this part are… to assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process." CAA § 160(5); 42 U.S.C. §7470(5).

terminals. Moreover, the Application provides no information on the characterization of or emissions from upstream raw material sources (feeder pipelines, etc.) that will be processed at the facility. Upstream raw material supplies or downstream finished product receivers may

> still be subject to permitting because they are either individually major or a support facility making significant contributions to the product of a collocated major facility. The support facility test dictates that, even where there are two or more industrial groupings at a commonly owned facility, these groupings should be considered together if the output of one is more than 50 per cent devoted to support of another.[29]

Based on the lack of definition of the facility boundary itself, it is impossible to ascertain if all support facility emissions are properly accounted for in the Application and the Draft Permit.

2. *The Application Fails To Characterize Any Emissions Of NSR-Regulated Pollutants From Numerous Emissions Units Discussed Or Implied In The Application*

First, the Application provides no information on emissions of NSR-regulated pollutants from flares other than from flare pilot gas combustion. While pilot gas emissions are expected, they are generally small compared to the significant emissions from actual flaring episodes. In turn, the volume and composition of the gases that are released and combusted during flaring operations depends on factors such as the source of the flare gas, the nature of the flaring event (i.e., whether planned or unplanned), the design of the source of the flare gases, the maintenance practices of the refinery, the source and nature of the crude and other products processed in the refinery, and others. In addition to these factors, the resultant emissions also depend on the design of the flares themselves. Yet, none of these are discussed in the Application and it is simply assumed that the non-pilot flaring emissions are zero. This is a significant underestimation of the actual flaring emissions from the refinery. As such, its exclusion fatally underestimates the emissions of all expected criteria (NOx, CO, SO_2, VOCs, PM_{10}, $PM_{2.5}$), hazardous, and other regulated pollutants. It therefore undermines all of the subsequent analyses (such as dispersion modeling and air toxics impact analyses) and their conclusions.

Second, the Application provides no information on emissions of VOCs, condensible particulate matter ("PM") and CO from the closed vent system for the wastewater collection system. The Application does not show that the closed vent system will operate under negative pressure at all locations or will meet the requirements of a permanent total enclosure. The Application does not connect the design of the closed vent system to the emissions calculations, thereby leaving the latter without any support.

Third, the Application provides no information on the emissions resulting from the treatment of solid wastes associated with wastewater treatment (i.e., belt filter presses and

[29] EPA Proposed Interim Approval of West Virginia Operating Permits Program, 60 Fed. Reg. 44799, 44800 (Aug. 29, 1995). *See also* Requirements for Preparation, Adoption, and Submittal of Implementation Plans, 45 Fed. Reg. 52676, 52695 (Aug., 7, 1980) and the Application at 29.

wastewater treatment plant sludge storage). These emissions could include VOCs as well as PM emissions.

Fourth, the Application also provides no information on emissions resulting from maintenance coating and tank degassing activities, which will likely produce emissions of criteria pollutants. Tank degassing is a routine aspect of tank maintenance at refineries. Similarly venting or degassing of various coker components is also routine. These emissions have not been considered or estimated in the Application.

Fifth, the Application provides no information on ammonia or hydrogen chloride emissions from the SRU Thermal Oxidizer Vents. Sulfur recovery unit thermal oxidizer exhausts are likely to contain ammonia and hydrogen chloride from process carryover into the Sulfur Recovery Units. However, the Applicant failed to characterize ammonia and hydrogen chloride emissions from the SRU Thermal Oxidizer vents.

While not every one of these omitted emissions will, in themselves, constitute substantial emissions of particular pollutants, put together, they make up a significant quantity of emissions that the Applicant did not consider in calculating total emissions. Thus, by not taking them into account, the Applicant severely underestimates the proposed facility's emissions of many NSR-regulated pollutants. All further calculations and decisions made based on these underestimated emissions calculations are, as such, unreliable.

3. *The Application Provides No Information On The Emissions Of Several NSR-Regulated Pollutants From Any Emissions Unit*

Nowhere in the Application does the Applicant provide information on the emissions of hydrogen sulfide; greenhouse gases other than carbon dioxide, such as methane and N_2O; or the refrigerants (HCFCs)[30] or ammonia which may be used in the Rectisol Unit of the IGCC power plant.

4. *The Application Does Not Identify The Fate Of Nitrogen Oxides In The Rectisol Process*

The Applicant should identify the fate of nitrogen oxides that may be contained in syngas from oxidation of any nitrogen compounds contained in coke or coke feedstocks. Nitrogen oxide concentrations in CO_2 vent gas should be identified under all Rectisol plant operating conditions.

5. *The Application Does Not Properly Identify IGCC Plant Gasification System Feedstock Injection Process Fugitives*

The Application shows a slurry tank that feeds ground petroleum coke and coal to the gasification process. There are no details or equipment indications in how this introduction to

[30] Many HCFCs are NSR-regulated pollutants because they are listed in 42 U.S.C. § 7671a(b) as Class II substances regulated under Title VI of the Clean Air Act. HCFCs are regulated under NSR at 40 C.F.R. § 52.21(b)(50)(iii). If the Rectisol refrigeration system employs NSR-regulated HCFCs, the Application should include emissions characterizations of those HCFCs, or should affirmatively state that no NSR - regulated HCFCs are used.

the gasifier is actually made. Gasifier fugitive emissions and backflows must be controlled when charging solids and slurries to a pressurized gasifier.

If lock-hoppers are used, such devices will have a gas discharge and no details are provided on the disposition of gas from such devices.

B. The Application Does Not Provide Enough Information To Verify The Emissions Characterizations Of Several NSR-Regulated Pollutants

First, the Application does not contain a sufficiently detailed map of the site road network necessary to verify the Applicant's fugitive PM emissions calculations. Modeling fugitive emissions properly requires accurate spatial allocation of such emissions. Without proper spatial allocation, the impacts analysis is unreliable. As such, spatial allocation for fugitive emissions such as traffic-related PM emissions requires the identification of the road network. The application does not provide this.

Second, the Applicant fails to submit sufficient information to allow verification of the sulfur recovery unit sulfur dioxide, hydrogen sulfide and total reduced sulfur emissions. All of the emission projections for the Sulfur Recovery Unit ("SRU") tailgas incinerators depend on a single disclosure of the total maximum expected sulfur input to the sulfur recovery units of 2,040 long tons of sulfur per day. No basis is presented for the claim of 2,040 long tons/day. There is no information providing a sulfur mass balance for the refinery and IGCC plant on either a short term or long term basis. There is no information on the sulfur content of crude oil expected for delivery to the refinery.

The Applicant should already have performed a sulfur mass balance for the facility that could be provided as an Application supplement. Because there is no crude sulfur input information and no IGCC plant/refinery sulfur mass balance, it is impossible to verify the emission estimation that relies on the 2,040 long ton per day sulfur throughput provided by the Applicant for the SRU. Moreover, without the information above, there is no way to determine whether the overall refinery production throughput limit will function as a physical throughput limitation on the potential to emit for the sulfur recovery units. In the absence of full disclosure of the basis for 2040 long ton/day sulfur throughput to the SRU, the Draft Permit should be amended to place a 2040 long ton/day operational restriction physically limiting the SO_2/H_2S/TRS potential to emit of the six SRUs.

Third, the Applicant failed to provide adequate information regarding the destruction efficiency of SRU thermal oxidizers during times of SRU process sulfur flow transients to verify emissions of NSR-pollutants from SRU thermal oxidizers. Under a worst case condition of Claus Unit loss, a Thermal Oxidizer on the end of the SRU process train will receive a maximum amount of sulfur feed equivalent to a rate of 23.8 tons of sulfur per hour. Nothing in the Application provides any detailed information about the planned SRU Thermal Oxidizers.

Diversion of very large amounts of waste acid gas to the Oxidizers for incineration must be evaluated to ensure that the Thermal Oxidizers are not overloaded under such maximum sulfur feed transient conditions. An overloaded Thermal Oxidizer may not necessarily maintain acceptable acid gas destruction efficiency. If the planned sulfur flow to these incineration devices reduces the destruction efficiency for inlet acid gas feed, the net result will be emissions of toxic air contaminants such as hydrogen sulfide, methyl mercaptan, carbonyl sulfide, carbon disulfide and dimethyl sulfide.

Fourth, the Application does not contain sufficient information to verify if the carbon dioxide (CO_2) emissions calculation included in Appendix H of the Application is correct. In Appendix H of the Application, the Applicant notes that many design details for CO_2-emitting refinery equipment are not yet determined. Without such design details it is impossible to verify the CO_2 emissions estimate provided.

Fifth, the Application does not provide sufficiently detailed information about the design and configuration of wastewater sewage and transport system to verify whether the closed vent system to control VOC emissions from wastewater treatment units will also control VOC emissions from the facility wastewater sewer system.

Sixth, the Applicant failed to provide adequate information on physical aspects and expected maximum process gas releases and emissions of the refinery flaring, venting and pressure relief systems to verify compliance with the physical flare design performance objectives of 40 C.F.R. §60.18. The application discloses very few details on refinery physical and engineering aspects of flaring, venting and pressure relief systems. Further, the Application contains no specific information at all on flare gas manifold gas collection systems and the process pressure operated relief valves ("PORVs") which discharge to such a system. There is no information on the use of ruptured disks, either with or without the presence of atmospheric discharge PORVs.

Moreover, the refinery portion of the Application contains no information providing the physical, time duration and maximum gas volume characteristics of vent gas for each process unit that may generate flow to be released by an atmospheric release PORV or that may be directed to a flare gas manifold collection system for each part of the refinery manifold system. The application indicates a "preliminary height" of five refinery flare stacks to be 350 ft ("as required to limit the exposure of ground level equipment and personnel to the radiant heat of the flare flame.")[31] However, the air quality modeling study indicates that two of the five refinery flare stacks will be at 200 feet high and and three others 213 feet high.

SD EForm- 1633-V1 submitted for the five refinery flares show gas discharge velocities of 1.00 feet per second or less. However such a flue gas condition would reflect only gas pilot light operation plus discharge of flare purge gas and steam, not gas flow rates associated with flare gas relief and flaring incidents.

Further, there is no detailed information on any means of process refinery fuel gas volumetric storage, process gas blowdown and recovery systems, flare gas compressor systems, rupture disks, flame arresters, knock-out pots, gas flow volume metering, and other relevant physical elements of flaring, gas collection manifold and pressure relief systems. While schematic drawings may show some of these physical elements, there is no physical process rate, process input/output/intermediate flow or mass rate specification sufficient to evaluate the flare

[31] The Application, at 16, Section 2.2.15.

and process gas relief systems and their emissions.

The available information in the Application does not address design information showing what measures of redundancy and process reliability are provided to ensure continuous availability of flare and relief system operation and emission reduction through process stability control and use of redundant backup and/or co-parallel physical systems (i.e. backup flare gas compressor capability, parallel process gas piping trains and valves for flame arrester, gas sensor and ruptured disk maintenance).

The Statement of Basis contains no explanation why the Applicant should not have been required to submit most of the physical system specification content of the flare minimization plans at Sections 12.3 and 13.3 of the Draft Permit in the Application that was submitted and erroneously certified as complete by DENR. Commentors are not aware of any compelling basis why such information could not be made available based on the Applicant's design of the refinery process equipment.

Aside from the flare pilot gas combustion emissions, the Application contains no maximum potential to emit characterization for refinery flare emissions during times of process gas flare combustion and of PORV atmospheric releases. These emissions are significant. For example, refineries in Southern California and in the Bay Area are required to report on all significant flaring events including gas volumes flared and the emissions of SO_2 and VOC resultant. These reports show that individual flaring events can last from hours to days and can involve the release of tens of millions of cubic feet of gas and hundreds of tons of SO_2.[32] The Applicant should have been able to develop maximum design-basis flaring events that might occur. Such flaring event postulation must have been part of the Applicant's current design plans on the proposed flares. There is no practical or engineering reason why such information should not have been included in the Application, along with associated emission calculations.

The Application lists a total number of PORVs (31 total)[33] and Commentors presume these to be atmospheric release PORVs because of their presence in the equipment leaks emission table. There is no information at all indicating which process units are served by these atmospheric discharge PORVs. No information is provided at all on the physical location, height and process gas characteristics associated with the planned PORVs.

The Application contains no information at all on either typical or maximum emission rates associated with PORV openings or valve chattering[34] and/or emissions from the five refinery flares, and other physical information necessary to determine the maximum potential to emit for all relevant averaging times.

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[32] *See* monthly flare emissions reports for the Bay Area Refineries, available at: http://www.baaqmd.gov/enf/flares/.

[33] The Application, at Appendix C, Equipment Leak Emissions Table.

[34] Such episodic emissions from PORVs are separately identifiable and distinguishable from the PORV component leak emissions shown in Appendix C.

The Applicant is under a clear obligation to provide source emission characterization under the PSD rule. That flare emissions would occur during startups/shutdowns, malfunction and maintenance events does not mean that such emissions and processes can be excluded from characterization of the maximum potential to emit and evaluation for BACT determination.

The failure of the Applicant to provide information identified in this subsection means that maximum facility emissions cannot be determined, that current source emission estimates and ambient air quality impacts are understated, and that the Applicant has not provided enough information to allow verification that its flaring and pressure relief system will have acceptable reliability, emission control performance and environmentally acceptable impacts. These failures mean DENR's draft decision violates requirements at SDCL §34A-10-8 requiring DENR to determine all "pollution, impairment and destruction" of natural resources and to evaluate all "feasible and prudent" alternatives to allowing Applicant's plans for an undisclosed magnitude of pollutant emissions from flaring and pressure relief systems for which control technology evaluation has not been provided in a pre-construction permit review.

When no information is available in the Application setting forth design-basis maximum flaregas generation that will be managed by flaring upon process equipment operation, malfunction or maintenance, there is no way to ensure that tip velocities will remain below the maximum velocity provided under 40 C.F.R. §60.18. Thus, the failure of the Application to actually supply such information means that flare performance characteristics that are supposed to be addressed by the maximum flare tip velocity requirements of 40 C.F.R. §60.18 cannot be assured.

C. <u>The Application Incorrectly Characterizes Emissions Of NSR-Regulated Pollutants From Several Emissions Units of the Proposed Facility</u>

1. *The Application Fails To Take Numerous Factors Into Account In Calculating Flare Emissions*

The assumption that applicant and DENR make that all flaring systems, including conventional elevated steam-assisted refinery flares, always achieve 98+% control efficiency VOCs and total reduced sulfur compounds is improper. Numerous factors can impact the control efficiency of flares during regular operating scenarios, and neither the Applicant nor DENR appear to have taken those factors into account in determining flare control efficiency and correlated flare emissions. For example, combustion efficiency of conventional flares can be adversely affected by an excessively high or low tip gas exit velocity, increasing cross-wind interferences, low gas BTU content, inadequate or excessive steam assist flows and gas content molecular weight.

Wind, in particular, can be an important factor in decreasing flare control efficiency. Wind speed significant affects flare emissions from refineries and chemical plants.[35] Emission factors for industrial flares were determined based on the premise that 98 to 99 percent of VOCs

[35] Robert E. Levy et al., Indus. Prof. for Clean Air, Reducing Emissions from Plant Flares (No. 61) (Apr. 24, 2006).

passing through the flare are destroyed.[36] However, as wind speeds increase, flares become less efficient and as such destroy less VOCs.[37] Flares' destruction efficiency (flares' ability to destroy VOCs) quickly decreases as wind speed rise from one to six meters per second.[38] One 2001 study found that "[a]s wind speeds increased beyond six meters per second, combustion efficiencies tended to level off at values between 10 and 15%."[39] The study also reports that "[t]heoretical considerations and observational evidence suggest that flare combustion efficiency typically may be at ~ 70% at low wind speeds ($U \leq 3.5$ m/sec). They should be even less at higher wind speeds."[40]

Despite this significant evidence that wind speeds vastly affect flare destruction efficiency, and thus VOC emissions from flares, the Applicant entirely failed to take wind speeds into account in calculating estimated VOC emissions or making a BACT VOC determination. It is likely, given the design of the flares proposed, that actual destruction efficiencies for VOCs will be lower than the assumed 98% value, thereby increasing such emissions from that assumed in the Application. Indeed, available research indicates that expected control efficiencies of conventional open air assisted flare can drop considerably below 98% control.[41] [42]

In addition to failing to consider factors affecting flare control efficiency during regular operating scenarios, neither the Applicant nor DENR took into consideration flare emissions during periods of startup, shutdown and malfunction ("SSM"). A recent study found that flare emissions produced during one single SSM event can exceed annual average flare emissions.[43] In failing to consider flare emissions during SSM period, the Applicant inaccurately calculated emissions of VOCs and other pollutants from the facility.

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[36] Douglas M. Leahey et al., Theoretical and Observational Assessment of Flare Efficiency, 51 J. Air & Waste Mgmt. 1610, 1611 (2001).

[37] U.S. EPA, *VOC Fugitive Losses: New Monitors, Emission Losses, and Potential Policy Gaps*, at viii (2006) (noting that "the emission factor for flare estimation is based on a flare operating in still air conditions").

[38] Leahey et al., *supra* note 36, at 1611.

[39] *Id.*

[40] *Id.* at 1615.

[41] D. M. Leahey, K. Preson, M. Strosher, *Technical Paper: Theoretical and Observational Assessments of Flare Efficiencies*, JAWMA 51:1610 (2001) (in this paper the author examined actual control efficiency data and compared it to modeled combustion efficiency of some actual units. Actual and predicted combustion efficiencies observed were as low as 68-69%).

[42] T. R. Blackwood, *Technical Paper: An Evaluation of Flare Combustion Efficiency Using Open-Path Fourier Transform Infrared Technology*, JAWMA 50:1714 (2000) (solution gas flaring combustion efficiency was found to be 64-71% under worst case conditions).

[43] Levy et al., *supra* note 35, at 10.

2. *The Application Fails To Properly And Completely Review The Potentials For Transient Sulfur Dioxide Emissions From The SRU Thermal Oxidizer Vents*

The Applicant has failed to properly and comprehensively address process and emissions management of transient acid gas combustion for sulfur recovery unit thermal oxidation units vents in a manner that demonstrates the environmental acceptability of potential acid gas releases. As noted in the separate section, the Applicant's SRU acid gas emission characterization depends exclusively on the Applicant's admission of the maximum daily process input rate of 2,040 long tons per day. For purposes only of discussion in this subsection, we accept this admission plus the Applicant's statements that a Claus process train will remove 97% of the input sulfur and that the Claus process plus the Tailgas Treating Unit ("TTU") together will remove 99.7% of sulfur input to the SRU. We also accept the Applicant's statement of planning to operate only 4 of the 6 sulfur recovery units at any one time, except for startup/shutdown periods. At 2,040 long tons per day or 190,400 pounds of sulfur input per hour, the maximum sulfur input to any single SRU will be 47,600 pounds of sulfur per hour.

Under a postulated unanticipated process breakdown for a single Tailgas Treating Unit that follows only one of the Claus SRU process trains, sulfur recovery would drop to 97%, with a resulting 1,428 lbs of sulfur input to the Thermal Oxidizer with resulting sulfur dioxide emissions at a rate of 2,856 lbs per hour for as long a time as would occur before the Applicant could reduce the sulfur input rate through both sour water and rich amine storage and/or divert sulfur input to a spare SRU either undergoing or completing process startup.

Under a postulated worst-case, sudden, unanticipated operational loss from process breakdown of a Claus process train, sulfur removal efficiency goes to 0% as the TTU isn't designed to handle acid gases at 20-40,000 ppmv that are stripped from rich methyl diethanolamine solution, and it must also shut down or reduce/divert input acid gas flow.

Immediately after a worst-case, sudden, unanticipated loss of a Claus plant, an immediate disposition of the single SRU train sulfur input at the rate of 47,600 pounds of sulfur per hour sulfur will end up in the SRU train Thermal Oxidizer until the operator can reduce acid gas generation and/or divert the flow to another working SRU process train. As such, the Thermal Oxidizer vent stack will have an emission rate equivalent to 95,200 pounds (47.6 tons) per hour of sulfur dioxide emissions until such time that the HEC either reduces acid gas generation by 47,600 pounds per hour, or otherwise finds a way to divert such acid gas to other SRU process trains. If sulfur combustion efficiency dipped to a modest 99.5%, the resulting hydrogen sulfide emissions would be about 239 lbs per hour.

The large sulfur dioxide emissions under the above worst case conditions of sudden, unanticipated loss of a TTU or SRU-TTU would be released from a vent stack that is only 100 feet high. There is no demonstration that this stack height is sufficient or that dispersion of such transient emissions will be adequate.

Nothing in the Application demonstrates the environmental acceptability of such a large emission on ambient air quality, odors and compliance with the primary and secondary sulfur dioxide NAAQS and PSD increments.

3. *The Application Fails To Correctly Calculate Carbon Monoxide Emissions From The Gasification Flare*

In calculating the carbon monoxide emission rate for gasification flare operation, it is error for DENR and the Applicant to rely on a carbon monoxide emission factor for the combustion of natural gas.

Although the Applicant indicates that all gasification flare gas will always be "cleaned," no diagrams or schematics were submitted showing the flare gas collection system in this process area. We question the statements made about ensuring that all flare gas is cleaned before being sent to the gasification flare. If the Applicant's statements are to be relied upon, this would mean that process gas pressure relief associated with the gasifier and other IGCC Plant components must pass always through intervening process units. We question whether such disposition of gases through other processes during non-routine events at the gasifier represents an acceptable process safety approach to gasifier process gas releases.

The Draft Permit should not issue until all such details about IGCC Plant waste process gas and associated collection systems are shown in a detailed technical diagram.

If gasification flaring events are associated with upsets in the shift reaction, considerably more carbon monoxide process gas will be directed to the gasification flare. Calculation of carbon monoxide emissions should then be based on oxidation rollback approaches rather than emission factors based on the combustion of natural gas.

VI. The Application Fails To Demonstrate That The HEC Is Subject To The Best Available Control Technology ("BACT") For Each Pollutant Subject To Regulation Under The Clean Air Act That Will Be Emitted From The HEC[44]

A. No PSD Permit May Be Granted for A Major Emitting Facility Unless BACT Determinations Are Made For All Pollutants Subject to Regulation Under the Act

The authorization of DENR to carry out a PSD program is intended to ensure that South Dakota-issued permits reflect all Federal Clean Air Act requirements. These requirements include the need to characterize emissions from all pollutant-generating activities, the need to ensure that all pollutant-generating activities and emission units at new major stationary sources of air pollution are subject to pre-construction BACT review, and the need for federally enforceable BACT emission limitations, monitoring, recordkeeping and reporting requirements to be contained in South Dakota PSD permits.

In fact, DENR has adopted most of the PSD regulations at 40 C.F.R. §52.21, *et seq.*, including the definition of BACT.[45] Under the PSD requirements, the Applicant must submit a

[44] "No major emitting facility...may be constructed in any area to which this part applies unless...the proposed facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility." CAA §165, 42 U.S.C. §7475(a)(4).

[45] 40 C.F.R. §52.21(b)(12).

BACT demonstration for each pollutant-generating activity and emission unit for each pollutant emitted in amounts beyond the significant emission thresholds.

"No major emitting facility... may be constructed in any [attainment] area unless...the proposed facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or are which results from, such facility."[46] Under PSD program regulations, best available control technology is defined as follows:

> *Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 C.F.R. parts 60 and 61. If the Administrator determines that technological or economic limitations on the Application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the Application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results"[47] (emphasis added).

In 1990, EPA wrote a draft NSR manual providing a five-step, top-down process which, though guidance, has consistently been interpreted to lead to proper BACT determinations.[48] Though an applicant is not absolutely required to utilize the top-down process in making BACT determinations,[49] use of that process will ensure that the final emission limitations selected conform to BACT as defined at 40 C.F.R. §52.21(b)(12).

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[46] 42 U.S.C. 7475(a)(4).

[47] 40 C.F.R. §52.21(b)(12).

[48] *See* U.S.EPA, *Draft NSR Guidance Manual*, at Section B (October 1990), available at: http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/1990wman.pdf.

[49] *See Alaska Dept. of Environmental Conservation v. E.P.A.*, 540 U.S. 461, 475 (2004).

B. The Application Makes Numerous Improper BACT Determinations By Failing To Follow The Top-Down Procedure

The Applicant's attempts to conduct its BACT analysis using the five-step top-down process are deficient. At Step 1 of the five-step process, all applicable control strategies and control approaches are identified for the pollutant in question from the source in question. In order to determine such applicable strategies and controls, the Applicant is supposed to review various sources listed in EPA guidance and identify such strategies and controls. As an example, most applicants begin with a review of EPA's RACT BACT LAER Clearinghouse ("RBLC") available on the internet. There is no mention of the RBLC in the Application. If it was consulted, there is no discernable tie to its findings and the BACT analysis. Other sources include controls being used in other refineries around the world, transfer technologies that may be feasible in other industries, etc. None of this is found in discussions of any of the source/pollutant combinations in the Application. Even in instances when some Step 1 controls are identified, it is impossible to gauge their completeness. If some controls can have multiple levels of efficiency based on design considerations (such as SCRs for NOx control from heaters, etc.), then the relevant design-based details should be provided. This was not done. In all, Step 1 appears to be either incomplete or unsupported, such that the rest of the analysis is significantly compromised. In most instances, BACT is simply stated as a conclusion, with no details or support.

C. The Application Provides Insufficient Information To Verify The Cost Component Of Its BACT Determinations

While there are deficiencies in the other steps in many of the analysis, one noteworthy deficiency is the treatment of costs in BACT analysis. Cost considerations are legitimate in BACT determinations but they have to be supported. In all instances that the Application relies on costs to eliminate a top-technology, there is no support provided for the cost data used. Customarily provided information, such as vendor quotes or engineering cost analyses, is lacking. Cost figures are simply stated without any basis. As such, none of the cost conclusions in the Application can be verified or relied upon.

D. The Application Makes BACT Determinations For NSR-Regulated Pollutants Without Considering Startup, Shutdown And Malfunction ("SSM") Operating Scenarios

Startup, shutdown and malfunction operating scenarios are considered part of normal operations for any source. BACT applies to all normal operations. Therefore, all SSM scenarios must be identified and defined because they will likely include different emissions rates of many pollutants than will occur during non-SSM periods. Without knowing the emissions during SSM operating scenarios, it is impossible to evaluate if BACT determinations were correctly made, as BACT must address process technology to reduce emissions during SSM - as well as regular - facility operations.[50]

[50] *See also* Section XV below.

E. The Draft Permit Contains Unacceptable Modification To The Meaning Of Short Term BACT Emissions Limitations By Requiring Compliance Determinations On Short Term Emission Limitations As Measured By Continuing Emissions Monitors To Use A 365 Day Averaging Period

The Draft Permit contains several footnoted references in the Section 4 following each BACT emission limitation table for sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide and hydrogen sulfide that modifies the effect of each emission limitation referenced depending on what data is used to measure and determine compliance.

"[1] – Unless otherwise noted, compliance with the emission limit is based on a 24-hour rolling average, excluding periods of startup, shutdown, and malfunctions, and based on a 365-day rolling average, including periods of startup, shutdown, and malfunctions using a continuous emission monitoring system that meets the procedures and requirements specified in permit condition 11.1;"[51]

"[4] – Compliance with the emission limit is based on a 365-day rolling average, including periods of startup, shutdown, and malfunctions using a continuous emission monitoring system that meets the procedures and requirements specified in permit condition 11.1;"[52]

"[7] – Compliance with the emission limit is based on a 3-hour rolling average, excluding periods of startup, shutdown, and malfunctions, and based on a 365-day rolling average, including periods of startup, shutdown, and malfunctions using a continuous emission monitoring system that meets the procedures and requirements specified in permit condition 11.1;"[53]

Many of these footnoted qualifications affect the emission limitations in the BACT tables for short term averaging times (1 hr to 24 hrs). The effect of DENR's acceptance of these 365-day averaging time qualifiers is highly objectionable for the following reasons.

First, the effect of such these 365-day averaging time footnoted qualifications on emission limitations is to impermissibly change the meaning and stringency of short term BACT emission limitations depending on how compliance with such limitations is measured. Under 40 C.F.R. 52.21(b)(12), BACT emission limits are control technology-based limitations solely based on the BACT process set forth in that regulation. After the determination is made that the setting of a numerical emission limitation is feasible and practical, no provision or decision making standard of review under the BACT definition allows the method by which emission monitoring is to be conducted to affect the decision on the stringency of the emission limitation. In this circumstance, the entire province of the BACT emission limitation determination rests on the determination of the maximum degree of control achievable, consistent with energy, environmental and economic considerations. No aspect of a review of the energy, environmental

[51] The Draft Permit, at 35, Footnote #1 on sulfur dioxide BACT emission limit Table 4.2.

[52] The Draft Permit, at 35, Footnote #4 on sulfur dioxide BACT emission limit Table 4.2.

[53] The Draft Permit, at 35, Footnote #7 on sulfur dioxide BACT emission limit Table 4.2.

and economic effects of a BACT control decision and the setting of the stringency of a numerical BACT emission limitation can be affected by changing the methods of measuring the emissions for compliance purposes, assuming all stack testing and continuous emission monitoring methods meet appropriate QA/QC and monitoring technology requirements.

Second, the DENR's Draft Permit 365-day averaging CEM data compliance test limitations on short emission limitation enforceability create an additional, substantial layer of needless complexity when such emission reporting and compliance evaluation are reviewed. The 365-day averaging approach to short term emission limitations departs substantially from prevailing practices of traditional NSPS quarterly emissions reporting and compliance evaluation.

Third, the PSD air quality evaluation procedures for NAAQS and PSD increment protection relies upon a specification of allowable emissions provided by the BACT emission limitation in the permit. The Applicant's air quality modeling studies assumed short term emissions would be no more than those limits as specified in the permit as an absolute magnitude of allowable numerical pollutant emissions.

The effect of the Draft Permit provisions allowing 365 day averaging times on short term emission limitation compliance evaluation is to dramatically increase the allowable emissions variability on a short term basis. The short term emission limits can no longer be considered maximum ceiling values which will not be exceeded, even on a short term basis.

DENR has agreed to abide by the air quality modeling guideline at 40 C.F.R. Part 51, Appendix W which requires that source term emission inputs to air quality models be based on allowable emissions associated with the maximum design basis source operation and process rate and the allowable potential to emit.[54] By requiring 365 day averaging times on compliance evaluation through CEM data of short term emission limitations, the effect of such modified emission limits is to allow short term emission transients far exceeding any maximum ceiling emission values used in air quality modeling. The effect of DENR adoption of short term emission limitations with the 365 day averaging time CEM data compliance evaluation is to nullify the reliability of the Applicant's air quality modeling conclusions for demonstrating ambient impact compliance with NAAQS standards and with PSD increment consumption.

F. <u>The Application Does Not Make A Proper BACT Determination For Several NSR-Regulated Pollutants Emitted From Several Emissions Units</u>

1. *The Application Fails to Make Required BACT Determinations For Refinery And IGCC Power Plant Wastewater Collection Systems*

Refinery wastewater collection systems produce emissions, and are thus emissions units; as such, required PSD BACT review must address wastewater collection. At the proposed facility the IGCC Power Plant also contains wastewater drains with potential for VOC and HAP emissions. Aside from just giving the number of drains at the IGCC Power Plant only, there is no physical characterization at all of the facility's wastewater collection system and no attempt to

[54] *See* discussion in Sections 8 and 10 in Appendix W.

characterize emissions from this pollutant generating activity. Failure to provide physical information and emissions information means that no BACT review has taken place for the wastewater collection equipment, rendering the Application incomplete and not approvable.

The Applicant should have provided numerical and schematic representations of the wastewater collection system. All wastewater collection system components potentially involving emissions, including drains, vents, process equipment and tank containment sumps, junction boxes, manhole access points, crude de-salting systems, storage tanks (including sour water surge tanks), wastewater storage basins and outlets, should have been qualitatively and quantitatively described and evaluated for VOC BACT controls.

In a physically disparate wastewater collection system, all features of the ability of this system to collect, control and emit facility wastewater collection system VOCs and HAPs must be considered. The potential use of induced draft ventilation for outlet control and maintenance of the wastewater collection system under negative pressure should have been considered as an alternate BACT technology since increasing collection efficiency of waste gas collection systems intended for treatment is a necessary and appropriate part of a BACT determination.

2. *The Application Fails To Address VOC Emissions From Refinery Wastewater Treatment Plant Sludge Handling And Management*

There will undoubtedly be fugitive VOC emissions from belt filter presses and sludge handling containers and equipment. However, the Applicant made no BACT determination for such fugitive VOC emissions.

3. *The Application's BACT Determination For The Wastewater Treatment Plant Thermal Oxidizer Exhaust Fails To Address All Required Pollutants And Does Not Ensure That The Maximum Degree Of Emission Reduction Under The BACT Definition Has Been Achieved*

The Applicant's BACT Demonstration for the Wastewater Treatment Plant Thermal Oxidizers only addressed emissions of VOC and nitrogen oxide emissions. Although the DENR Statement of Basis considered other pollutants and review elements at this emission unit, the agency should have nevertheless determined that the Applicant's submittal was incomplete and not approvable, but DENR failed to do so.

Even considering the combined Applicant submittal with DENR's Statement of Basis showings, the BACT determination for this emission unit is still defective. The application contains no information or basis about the expected Thermal Oxidizer VOC, hydrogen sulfide and total reduced sulfur mass inlet rate, gas volume rates and no justification showing that a TO burner rate of only 1.0 MMbtu/hr provides sufficient TO heat release to gain the 98% emission control efficiency being claimed by the Applicant for the oxidizer unit. The Application claims that a WATER9 determination was used to set BACT VOC uncontrolled emission rates, but no such documentation was provided and the emission estimates are not verifiable. Benzene is a critical matter in refinery wastewater emissions, but there is no benzene, ethyl-benzene, toluene or xylene emission rates for airborne toxicant determination.

Further, the VOC BACT determination fails to conform to the "top-down" BACT determination method because there was no demonstration that 98% control efficiency should be considered a top level control that cannot be improved under any other technically or economically feasible control method. Alternate methods of VOC control, other than a conventional thermal oxidizer burning refinery fuel gas or natural gas, were never considered. These include flameless thermal oxidation using a ceramic honeycomb matrix bed, industrial biofilters, use of process gas as combustion air in a heater or boiler, or other methods of VOC control. Some of these methods may involve reducing expected NOX emissions.

The Application also does not address the effects of sulfur or metals (from oily aerosols) on the planned catalytic thermal oxidizer design.

Ultimately, the Statement of Basis indicated carbon monoxide limits of 0.08 lbs/MMbtu and 0.08 lbs/hr, but such limits are completely unsupported and unexplained. Calculation of CO emissions from a thermal oxidizer serving a refinery wastewater treatment plant should not be based on thermal oxidizer fuel consumption rates because of the btu content of the process gas being burned.

The Applicant also did not address particulate emissions from the WWTP thermal oxidizer. The DENR Statement of Basis said that 0.0075 lbs of PM (condensible and filterable) per million btu heat input should be considered as BACT. An Arizona refinery permit thermal oxidizer limit was cited, but the limit of 0.0075 lbs PM per MMbtu is also the same PM limit that is applicable to all of the heaters at the site. DENR did not say if the Arizona permit thermal oxidizer was for crude storage or for refined petroleum hydrocarbons, and this is important because of the effect of any sulfur contained in oxidized process gas and the effects these will have on thermal oxidizer particulate emissions (such as sulfates). In the case of process gas from covered API separators and DAF units, such gas is likely to contain significantly more hydrogen sulfide than would be expected from simply the combustion of cleaned refinery fuel gas combustion at 25 ppm hydrogen sulfide. Similarly, the sulfur dioxide BACT emission limitation that was set was only for the combustion of refinery fuel gas and does not consider any hydrogen sulfide released from wastewater.

The emission limitation purported as a NOx BACT limit in the Statement of Basis is 5 lbs of NOx per hour on a oxidizer shown with 1 million btu/hr heat input rate for an emission equivalent to 5 lbs of NOx per MMbtu heat input. There is no explanation of how either DENR or the Applicant arrived at the stated NOx BACT emission limitation. Nor is there any explanation of why the sizing of the oxidizer (i.e., 1 million Btu/hr) is adequate for this service. The Statement of Basis and the Application show selective catalytic reduction as a control for the WWTP thermal oxidizer, but DENR never showed any SCR unit on this emission unit in Table 1-1 of Description of Permitted Units, Operations, and Processes.

4. *DENR's Statement Of Basis And The Draft Permit Contain No Hydrogen Sulfide Or Total Reduced Sulfur BACT Review And Emission Limitations On Fugitive Emissions From Process Equipment Components*

Commentors note that DENR failed to review and make a finding on hydrogen sulfide and total reduced sulfur BACT emissions limitations addressing these fugitive pollutant emissions from facility process equipment component leaks. Facility process equipment component leaks constitute emission units requiring a BACT demonstration for hydrogen sulfide and total reduced sulfur for this facility, as these pollutants are emitted in significant amounts by this source. Failure to provide such a BACT demonstration and BACT emission limitation is a firm basis for denial of the Application.

5. *The Application Fails To Carry Out A "Top-Down" BACT Demonstration For Fugitive VOC Emissions From Facility Process Equipment Components*

The Applicant identified control options for fugitive VOC facility process equipment components,[55] but the list of controls is defective because of the Applicant's failure to include hand-held portable FTIR spectroscopic backscatter imaging video cameras for VOC leak detection (and other similar technologies) for quickly visualizing discharge plumes from leaks. The use of such portable video imaging technology confers the added benefit of showing any pin hole leaks in process equipment and piping that occur at other than designated component sites. As a result, such video imaging of VOC leaks helps to find conditions that may have process safety consequences.

The Applicant's submittal included a helpful list of process equipment components subject to VOC leaks in Section 4.10.1.1 of the Application (see p. 87-88). However, the actual emission calculation spreadsheets of Appendix C fail to identify population numbers for all of the equipment component types listed in Section 4.10.1.1. The Applicant should clearly identify population numbers for all such components, even if they are zero.

There are no VOC BACT emission limitations identified for fugitive process equipment component leaks in Section 4.4 of the Draft Permit. The provisions of section 14 appear to be little more than reference to minimum federal rule requirements arising from NSPS and MACT/NESHAPs requirements. If the Section 14 VOC emission limitations for facility process equipment component leaks were intended to be BACT emission limitations, then the BACT determination should have shown how such provisions were the result of a "top-down" BACT determination. No such showing was made in either the Application or the Statement of Basis.

Even if the Draft Permit Section 14 emission limitations were intended as VOC BACT limits, the Draft Permit limits still cannot be considered as a valid "top-down" BACT determination since DENR and the Applicant have both erroneously identified their Leak Detection and Repair (LDAR) program as the top level control. Nothing in the Section 14 LDAR requirements contain any of the top level controls "leakless" advanced component technologies identified by the Applicant in Section 4.10.1.2 of the Application (see p. 88). As a result, the Section 14 LDAR program is not a top level VOC BACT control for process equipment fugitive emissions.

The Applicant's actual selection of BACT in Section 4.10.1.6 for fugitive facility process equipment component leaks failed to include any of the "leakless" technologies, so it was not a top level control. The Applicant dismissed these top level "leakless" controls without making a showing why they would be eliminated on the basis of energy, environmental or economic

[55] *See* the Application, at 88, Section 4.10.1.2.

considerations. In practice, that would have required quantifying the effect of adoption of "leakless" components as an alternative to conventional components on some or all process equipment. Nothing in the Applicant's submittal provided any such showing. The Applicant thus failed to conform its VOC BACT review for fugitive process equipment emissions to the "top-down" BACT determination process. DENR's findings that a top level control was utilized and its approval of the VOC BACT determination are both in error.

In addition, there is no showing why leak definitions lower than the ones shown in Appendix C should not be considered and enforced for leak determination purposes. Finally, U.S. EPA National Enforcement Investigations Center staff has identified problems in refinery and petrochemical LDAR programs due to the failure of LDAR implementing personnel to spend a sufficient time testing with total organic carbon analyzers at each component. In VOC BACT determinations addressing LDAR activity, some consideration should be given to management information system automation of tracking of the duration of component testing to ensure self-audit and verification that adequate time is taken for leak testing at each component.

6. *The Application's Facility Process Equipment Component Physical Characterization And Fugitive Emission Characterization Is Problematic And Creates A Low Confidence That VOC BACT Has Been Properly Determined*

Commentors note the Applicant's statement of a leak definition of 10,000 ppmv in Section 5.1.10 of the Application, but the Appendix C calculation sheet shows either 500 or 100 ppmv leak definitions. No explanation is provided for this discrepancy. The Application contains no breakout showing the number of each process equipment components for each major process unit at the refinery and the IGCC power plant. This failure also has consequences for proper evaluation of airborne toxicants and odors from process equipment component fugitive emissions. There is no attempt at all in the Application to provide any basis for the absolute numbers of each of the components listed, so the emission calculation is ultimately unverifiable.

The Application contains no characterization at all of either individual or total hazardous air pollutants and airborne toxicants of consequence to any determination of human health and/or ecological risks. While hydrogen sulfide is considered, there is no evaluation of other reduced sulfur species, such as methyl mercaptan, carbon disulfide, carbonyl sulfide, dimethyl sulfide, phenyl- and benzene- mercaptans, thiophenes and other odorous compounds. This means that also there is no information about benzene, ethyl-benzene and other petroleum fractions that are airborne carcinogens. The Applicant's emission characterization for fugitive facility process equipment component emissions is contained in Appendix C and is minimally portrayed in just two pages. One page shows petroleum refinery VOC and hydrogen sulfide and the other page shows IGCC power plant VOC and hydrogen sulfide.

The Applicant's fugitive component emission spreadsheet in Appendix C displays some of its calculation results in a manner which does not conform to accepted practices for managing significant figures in the results of engineering and scientific calculations. There is no indication of potential process equipment components which are in acid gas service, but not in VOC service, for purposes of hydrogen sulfide and total reduced sulfur emissions characterization.

The Applicant lists 59 petroleum refinery compressor seals admitted as a potential population for VOC leaks, but lists zero compressor seals with potential for hydrogen sulfide leaks – a result which is at low confidence reliability for hydrogen sulfide emission characterization. The Applicant lists zero compressor seals for the IGCC power plant without saying whether or not leakless technology is being used for all such compressors.

Reliance on VOC total organic compounds as carbon leak detection equipment and Method 25/25A VOC determinations for leaks conducted in support of AP-42 factor development from facility means that the Application total VOC emissions characterization from process equipment components will be significantly understated. These methods will not consider the mass emission rate contribution to total VOC emissions occurring from refinery fugitive VOC emission compounds that contain sulfur, oxygen, chlorine and nitrogen. Methyl mercaptan is a highly relevant example.

7. *The Applicant Failed To Conduct A BACT Review For Site Roads Emissions*

The Applicant failed to conduct a required BACT determination for site road fugitive emissions. Allowing 20% opacity on site roads and parking lots does not constitute BACT for fugitive road visible emissions. Allowing the facility to delay pavement of site roads for up to a year after commencement of operation does not constitute a BACT emission control for roads.

The emission calculation for site roads depends on a very low silt loading factor of 0.4 grams per meter squared, when a considerably larger silt loading factor would be deemed appropriate for paved industrial roads. Nothing in the Draft Permit requires periodic silt loading testing. Nothing in the form of fugitive road emission controls described in the Draft Permit can be fairly described as being a likely control measure to achieve fugitive road emissions commensurate with a 0.4 grams per meter squared silt loading factor.

Section 16.3 road emission fugitive controls listed as wet suppression, vacuum sweeping and water flush are not all equally effective emission controls, so allowing the owner/operator the discretion to use the least effective, least costly method is not a proper BACT determination to control the fugitive roads emission unit. The site road emission calculation cannot be verified because the failure of the Applicant to submit a site road map and plan, and for the same reason, required trip length assumptions cannot be verified.

8. *The Applicant Failed To Make A Required BACT Determination For Other Site Fugitive Particulate Emissions*

Section 16.0 contemplates unpaved roads, open storage piles, waste pits, wash out concrete truck area and a coke pit. The Applicant has not provided the required particulate emission characterizations or BACT determinations for all such site material management units. The Applicant must be compelled to describe all such material management units that are planned. All material transfer processes must also be identified. If the facility is planning use of outdoor coal and coke piles, such storage, management and transfer processes must be identified and the Applicant must submit a BACT demonstration for fugitive emission controls at each site. No outdoor unenclosed sulfur storage should be allowed.

9. *PSD Permits Must Include Visible Emission Limitations for Emission Units Reflecting BACT*

The PSD rule definition of BACT[56] includes a requirement that visible emission limitations be set as part of a PSD BACT demonstration. The only visible emission limitations in the Draft Permit which might be considered as BACT opacity limits are the requirements for no visible emissions from the material handling building. The general 20% opacity limitation contained in the permit cannot be considered as a BACT visible emission limitation for several of the combustion and other sources proposed for the facility. Most enclosed combustion process sources at the proposed facility should not be allowed visible emissions greater than 10% opacity for a new source limit. Elevated flares should be put under a no smoking flare limit.

10. *The Application Fails To Include A Proper "Top-Down" BACT Determination For PM And VOC Emissions From The Cooling Tower*

Particulate emissions from cooling towers depend on the drift elimination efficiency and the total dissolved solids content of cooling water in recirculating systems. While the Applicant claims to have selected a state-of-the-art drift elimination efficiency for demister equipment for the cooling towers, the Applicant's submittal fails to properly address alternate BACT PM control targets associated with use and maintenance of cooling water with lower total dissolved solids aqueous concentrations.

While the Applicant's emission characterization assumed a 3,750 ppmw concentration of total dissolved solids ("TDS") in cooling water, there was no explanation or basis given for the 3,750 ppmw criteria and no basis for why a lower TDS was not technically and economically feasible. A proper "top-down" BACT review of this issue would consider the TDS concentration of available cooling tower make-up water, operation of cooling tower systems at alternative rates of cooling tower blowdown to achieve lower PM emissions through reduced TDS in cooling water and use of reverse osmosis for treatment of both cooling water intake and cooling tower blowdown. The 3,750 ppmw cooling water TDS concentration cannot be presented as a *fait accompli* in the cooling tower BACT determination without a basis and showing that demonstrates that maintaining a lower cooling water TDS concentration is ruled out on the basis of either technical feasibility, economics, environmental and/or energy considerations.

Finally, any PM BACT determination for the cooling tower should address automatic vs. manual systems to address cooling tower blowdown and maintenance of target TDS aqueous concentrations.

The Applicant's VOC emission characterization from the cooling tower is presented with an emission factor of 0.7 lb/million gallons of cooling water flow claimed to be from Section 5.1 of AP-42.[57] The Applicants cooling tower VOC BACT determination does not explain why the AP-42 factor should be considered as a BACT level of control for VOC emissions, or why this

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[56] *See* 40 C.F.R. §52.21(b)(12).

[57] *See* the Application, at 127, Section 5.1.4.

factor was used for emission characterization without exploring how BACT controls might allow lower emissions with a lower factor.

As noted by AP-42 itself, the publication of AP-42 air emission factors cannot be considered as a *pro forma* BACT determination:

> "Emission factors in AP-42 are neither EPA-recommended emission limits (e. g., best available control technology or BACT, or lowest achievable emission rate or LAER) nor standards (e. g., National Emission Standard for Hazardous Air Pollutants or NESHAP, or New Source Performance Standards or NSPS). **Use of these factors as source-specific permit limits and/or as emission regulation compliance determinations is not recommended by EPA.** Because emission factors essentially represent an average of a range of emission rates, approximately half of the subject sources will have emission rates greater than the emission factor and the other half will have emission rates less than the factor. As such, a permit limit using an AP-42 emission factor would result in half of the sources being in noncompliance"[58] (emphasis added).

Thus, simple reliance on the 0.7 lb VOC/million gallons of cooling water AP-42 emission factor cannot be considered as a selection of a "top-down" VOC BACT determination for this emission unit.

Although leak detection is offered as a VOC BACT emission limitation in the form of a work practice, the cooling water heat exchange leak detection and repair and VOC in cooling water detection requirements are indeterminate and vague:

> "14.13 Cooling tower heat exchanger. In accordance with ARSD 74:36:09:02, as referenced to 40 CFR §52.21(j)(3), the owner or operator shall install and operate hydrocarbon detectors downstream of the return water outlet from the cooling tower process heater exchange banks or units where a process fluid containing volatile organic compound is at a higher pressure than the cooling water. If hydrocarbons are found in the water a leak is detected. When a leak is detected, a first attempt at repair the leak shall be completed within 24 hours of detecting the leak. The leak shall be successfully repaired within 7 days of detecting the leak except for as provided in permit condition 14.12. Within 24 hours after the attempt to repair the leak has been completed, another reading based on the method that determined the leak shall be made to verify if the leak has been repaired."

There is no information on the VOC hydrocarbon detection method, the expected detection limit such a monitoring device would support, whether VOC monitoring is intermittent or continuous, or performance criteria for continuous monitoring systems. The Applicant should be able to name all process units now which will have heat exchangers in which the petroleum hydrocarbon stream is at a greater pressure than the cooling water loop. All of these monitoring requirements should be specifically named in the permit for each process and emission unit meeting the pressure test criterion. As presently written, the cooling tower provision doesn't contain self-executing requirements that are elements of the Draft Permit that are immediately enforceable.

[58] U.S. EPA, AP-42, Volume I, at 2 (Introduction) (1995).

Without the elements named in the prior paragraph and in the absence of needed recordkeeping and reporting requirements to support compliance assurances, the Draft Permit VOC BACT limits in the work practice condition above are not enforceable in practice.

A proper "top-down" VOC BACT determination for this source will necessarily require a review of physical characteristics of heat exchangers, including heat exchanger metallurgy, corrosion control and product physical parameters. The Applicant failed to include any such review.

In summary, the failure of the Applicant to provide a proper BACT demonstration on the cooling tower PM and VOC renders the Application technically deficient, incomplete and not approvable.

11. *The Draft Permit Contains Neither Emission Limitations Nor Compliance Monitoring Requirements For The Cooling Tower Sufficient To Ensure A PM BACT Level Of Emission Control Performance And Expected Emissions*

Merely providing a physical design requirement that the cooling towers demister pads are capable of 0.0005% drift elimination is not sufficient to ensure that operational emissions will be below those PM emissions depicted in the Application. The only way to ensure such a result is to perform periodic physical parameter monitoring to address recirculating cooling tower total dissolved solids ("TDS").

Without such TDS periodic monitoring, recordkeeping and exception reporting requirements, there are no assurances that cooling tower PM emissions will remain below projected emissions in the Application.

12. *The Application Must Address The Problem Of High Transient Carbon Monoxide Emissions For Short Term Averaging Times From IGCC Plant CO_2 Vent Discharges*

The Applicant's planned process equipment in the IGCC Plant uses a gasifier to convert coal and petroleum coke into synthesis gas, which contains hydrogen and carbon monoxide. Using a shift reaction that takes place with a reactor and probable use of a catalyst, the carbon monoxide is reacted with steam to produce hydrogen and carbon dioxide.

If there is a process upset in the shift reactor involving temperature variation that reduces the efficiency of the shift reactor, then increased concentrations of carbon monoxide will eventually find their way through the Rectisol gas cleaning process and be found in emissions from the carbon dioxide vent.

The Applicant has not conducted a BACT determination to set a carbon monoxide short term emission rate based on maximum process variability that will occur with the IGCC Plant Shift Reactor.

In the Applicant's air quality modeling report and its May, 2008 supplement, an emission rate of 2,279.29 pounds of carbon monoxide per hour was used. The Applicant has never mentioned such a high carbon monoxide emission rate from this vent anywhere else in the Application. If the Rectisol CO_2 vent and associated upstream processes have the potential to cause an emission of this magnitude, then the Applicant must address the BACT consequences of such a problem and whether the facility will be able to comply with the Draft Permit which contains a much lower emission limit.

13. *The Application Fails To Consider Technically Feasible Hydrogen Sulfide Controls For The Rectisol CO_2 Vent*

The CO_2 vent is depicted by the Applicant as being the single largest hydrogen sulfide emission source at the proposed facility at 19 tons per year. Although commentors under stand the process gas exhaust volume is large, the Applicant must still consider technically feasible control measures.

The Applicant failed to consider a packed tower with caustic scrubbing and industrial implementation of a bio-filtration as two technically feasible control approaches. If such approaches are to be eliminated, the Applicant must show that their use would be economically infeasible for such options are discarded.

G. <u>The Application's BACT Determination For Flares Is Flawed</u>

1. *The Application Fails To Show That Flare And Atmospheric Discharge Pressure Relief Systems Are Subject To Federally Enforceable Emission Limitations That Are Demonstrated To Reflect Application Of BACT*

Because of South Dakota's adoption of Federal PSD requirements, DENR is not free to make BACT determinations on a different basis or with a different stringency that what would be considered to be BACT throughout the United States. In the In re: ConocoPhillips Co., PSD Appeal No. 07-02, June 2, 2008 decision of EPA's Environmental Appeal Board, that body said:

> "Because the added provisions of the permit, which concerned flare-related emissions controls and monitoring requirements, were not appropriately identified or explained by IEPA, the Board was unable to evaluate the reasonableness and adequacy of these provisions. Nevertheless, mindful of the time-sensitive nature of PSD permitting, the Board provides certain observations for IEPA's consideration on remand, *including the need for a proper BACT analysis for CO emissions from flaring and, based on that analysis, appropriate, enforceable CO BACT controls."* (emphasis added)

Thus, EAB unmistakably identifies flaring systems as subject to the PSD BACT requirements and emission limitations reflecting a proper BACT determination must be incorporated into the Draft Permit after an approvable BACT demonstration is evaluated. We incorporate by reference, as if set forth in full herein, the complete language of the ConocoPhillips Settlement Agreement[59] identifying various control technologies that have not

[59] http://www.insideepa.com/secure/data_extra/dir_08/epa2008_1462.pdf.

been considered by the Applicant and assert the BACT evaluations are incomplete in that they have not identified these technologies and control strategies in their BACT analysis.

2. *Neither The Applicant Nor DENR Provide A Clearly Ascertainable Basis For Concluding That A BACT Emissions Limit For Flare And Pressure Relief Systems Is Technologically Or Economically Infeasible*

As noted above, the PSD regulations permit that, "if the Administrator determines that technological or economic limitations on the Application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the Application of best available control technology"[60] (emphasis added). In the ConocoPhillips case cited previously, EAB considered numerical emission limitations for flares within the meaning of the PSD BACT requirements binding on that facility. That Illinois EPA actually arrived at a numerical emission limitation for flare emissions of carbon monoxide illustrates that it is feasible to make such a determination.

In the present case, the Applicant has both failed to characterize the flare emissions of NSR-regulated pollutants and failed to provide any proposed BACT NSR regulated pollutant emission limitations for flares and pressure relief systems. DENR has accepted the Applicant's approach without making any separate determination of its own on either flare and pressure relief emissions or BACT numerical emission limitations.

Nothing in the DENR record shows any evidence of either an Applicant submittal or claim and/or a DENR finding that it is technically or economically infeasible to impose numerical emission limitations on flaring and pressure relief systems. The matter in the ConocoPhillips EAB BACT determination remand case stands at a minimum as a *prima facia* showing that it is technically and economically feasible to impose numerical emission limitations on flaring system carbon monoxide emissions.

Because neither the Applicant nor DENR have quantified any flaring and pressure relief emissions other than flare pilot gas combustion, there can be no claim by DENR that they have accomplished the required attempt to determine emission reductions achievable (as provided by the BACT definition) associated with imposition flaring work practices contained in the Flare Minimization Plans contained in the Draft Permit at Sections 12 and 13.

When neither the Applicant nor DENR have made the required demonstration that imposition of numerical emission limitations on flares and process relief systems is technically or economically infeasible, the Applicant's BACT demonstration ending only with work practice requirements and post-permit development of a Flare Minimization Plan must be disapproved as failing to comply with required BACT obligations.

[60] 40 C.F.R. §52.21(b)(12).

3. *The Application Makes Improper Assumptions Leading It To Fail To Make A Proper BACT Determination For Flares*

Because the Applicant and DENR inappropriately presume a control efficiency of 98+% for conventional elevated steam-assisted refinery flares, both assume that such flares constitute BACT and, for that reason, improperly fail to consider all physical alternatives to conventional elevated open air flare stacks. However, as noted previously, there is reason to doubt applicant's and DENR's assumed control efficiency. Combustion efficiency of conventional flares can be adversely affected by an excessively high or low tip gas exit velocity, increasing cross-wind interferences, low gas BTU content, inadequate or excessive steam assist flows and gas content molecular weight. Available research indicates that expected control efficiencies of conventional open air assisted flare can drop considerably below 98% control.[61] [62]

Because use of ground flares/thermal oxidizers with elevated refractory lined stacks or tip incinerators has the potential to increase flare combustion efficiency by eliminating cross wind effects and increasing flame zone temperatures, they must be considered as part of a proper BACT determination for flares. Neither applicant nor DENR should assume that such alternative flaring equipment will have the same control efficiency as conventional elevated open air flare stacks.

4. *The Application Does Not Submit A "Top-Down" BACT Demonstration For The Refinery Flares And Facility-Wide Pressure Relief System*

The Applicant claims that its BACT demonstration for flares conformed to EPA's "top-down" BACT demonstration[63] process as indicated in EPA's PSD Workbook.[64] However, the Applicant did not properly follow that process, as detailed below.

In a "top-down" BACT determination, all feasible control technologies must be identified. A control technology may include physical gas treatment devices or a change or alteration of a process to achieve an emission reduction. In the case of flaring and pressure relief systems, the following technically feasible measures were neither mentioned nor evaluated in the BACT demonstration provided by the Applicant:

Ground flare or thermal oxidizer enclosed by an elevated, refractory-lined stack;

Consolidating individual flares to a better controlled, larger flaring system serving more process units;

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[61] Leahey, Preson, and Strosher, *supra* note 41.

[62] Blackwood, *supra* note 42.

[63] The Applicant's claim that a "top-down" BACT determination process was used for the submittal can be found at Section 4.1.2 of the Application.

[64] *See* U.S. EPA, *supra* note 48, at Sections B.5-B.9.

Refractory-lined flare tip incinerator;

Installation of a second, backup flare gas compressor[65] in order to provide flare gas compression in the event of a primary compressor outage;[66]

Installation of gas storage spheres for storage of excessive generation of refinery fuel gas for later combustion utilization;

Installation of closed circuit television monitoring of refinery flares;

Use of automatic flare system controls for flare operations rather than manual controls on steam, purge and assist gas addition (in contrast to a manual control system);

Proper emission characterization from flares under the postulated conditions of maximum process gas generation (in contrast to the Applicant's and DENR's failures to quantify flare emissions) and evaluation of flare and pressure release system alternatives on short and long term emissions in contrast for the Applicant's specific proposal and the use of conventional elevated refinery flare stacks; and

Use of gas collection manifolds for flare gas recovery instead of the use of the 31 atmospheric discharge pressure operated relief valves (PORV) discharge points, to the extent that process safety allows such redirection of such otherwise uncontrolled atmospheric releases.

All of the above alternatives should have been considered by the Applicant and DENR in any BACT demonstration conforming to EPA's "top-down" process. The failure to consider these technically feasible options for BACT determination on the flaring and pressure relief systems means that the Applicant has not complied with the EPA "top-down" BACT determination process, contrary to the Applicant's claims.

In addition to the failure to consider all technically feasible control methods for flaring and pressure relief systems, the Applicant and DENR failed to provide emission characterization for all flare and pressure relief systems. Because of this failure, the BACT demonstration submitted cannot be considered to comply with EPA's "top-down" BACT determination process, which requires that control options be ranked by numerical control effectiveness and expected mass rate emissions on an hourly and annual basis. When there is no emission characterization of flaring and atmospheric releases, there can be no valid exposition of the ranking of control options by control efficiency and no assurance that the top control not eliminated by environmental, economic or energy considerations has been selected.

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[65] Redundant flare gas compressor capability has been installed in the flare gas recovery system at the ExxonMobil Baytown, TX refinery, so such parallel train compressor backup redundancy represents a feasible control already in use in the refinery industry.

[66] The schematic drawing at the Application PDF page 416 for the Flare and Flaregas Recovery System shows only a single flare gas recovery compressor.

For the reasons cited above, the Applicant has failed to provide the claimed "top-down" BACT demonstration, and the failure to have such assurances means that Applicant's demonstration for the flaring and pressure relief systems must be rejected.

5. *DENR's Proposed Decision Allowing The Applicant To Delay Most Physical Flaring And Pressure Relief Systems Information And BACT Work Practice Emission Limitations Disclosure To A Future Work Plan Development After Permit Issuance Violates Pre-Construction BACT Review And Public Participation Requirements Of The Clean Air Act*

The PSD program requires a pre-construction review requirement for new and modified major stationary sources of air pollution as required by the Clean Air Act.[67] Such a review must necessarily ensure the issued permit will contain emission limitations reflecting BACT and that the permit and its emission limitations has been subject to public comment and a public hearing.

In the present case, DENR certified the Application as complete when very little physical detail is provided on the refinery flaring and pressure relief systems. Then DENR proposed a Draft Permit allowing virtually all physical information disclosure on flaring and relief systems, together with the work practice control strategies for this emission unit, to be relegated to a future Flare Minimization Plan intended for creation after permit issuance. Nothing was submitted by the Applicant nor published by DENR that shows why elements of the future Flare Minimization Plan required by Conditions 12 and 13 represent a level of control commensurate with BACT requirements.

DENR's actions, inactions and tentative decision described in the preceding paragraph means the agency has failed to carry out necessary pre-construction review requirements and obstructed public review of proposed BACT emission limitations. DENR has apparently decided to allow the Applicant to put off disclosure of physical and design operational parameter information on the refinery flare and relief system when such physical information should be presently available based on the Applicant's present design concepts of the facility. Similarly, DENR has decided that no work practice control strategies that DENR considers as BACT in the Flare Minimization Plan will be evaluated prior to permit issuance.

Both of these DENR decisions constitute a violation of the requirement for pre-construction review, since DENR is abdicating its duty to carry out a pre-construction review of alleged BACT emission limitation work practice requirements that will supposedly be contained in a future Flare Minimization Plan that will not exist as of the date of permit issuance. Similarly, DENR's decision violates public participation requirements[68] since none of the flare and pressure relief system BACT emission limitations will be a part of the Draft Permit as it is proposed for public comment. The public is thus being deprived of the opportunity to know and comment on proposed BACT emission limitations for the flare and pressure relief system.

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[67] 42 U.S.C. §7475(a).

[68] 40 C.F.R. §52.21(q); 40 C.F.R. §124, Subpart A, public participation and decision-making regulations affecting PSD permits.

6. *The Draft Permit Requirement For A Future Flare Minimization Plan As A Required Work Practice Is Not, In Itself, A BACT Emission Limitation, And A Flare Minimization Plan That Is Not Subject To Pre-Construction Review And Disclosure To The Public Is Not A Valid BACT Emission Limitation*

Under Draft Permit Conditions 12.3 and 13.3, the Applicant is supposed to develop a Flare Minimization Plan ("FMP") covering the refinery flares and the IGCC plant gasification flare. The Draft Permit conditions do not require that the FMP be submitted to DENR or that the FMP be approved by DENR. There is no requirement that the FMP be available for public comment prior to adoption and for disclosure after adoption.

Under the Draft Permit, the Applicant is not under any obligation to demonstrate that the work plan management measures as a emission control strategy meets any standard for BACT control stringency or effectiveness. The Applicant has sole discretion to change the FMP at any time it chooses, including the relative stringency of any work plan control measures contained in the plan.

Under the circumstances, the FMP cannot be relied upon as having a BACT level of control stringency. Further, the FMP is not a federally enforceable BACT emission limitation because there is no certainty of the regulatory application of the FMP as an emission limitation, there is no certainty that the FMP will ever be available to the public, and the FMP can be changed at any time to any provision solely at the discretion of the Applicant.[69]

7. *The Application's BACT Determination For Short Term Sulfur Dioxide Emissions From The Sulfur Recovery Unit Thermal Oxidizer Vent Stacks Is Improper Because It Fails To Consider Claus Unit-Tailgas Treating Unit Process Train Outages*

In characterizing pound-per-hour emission rates from the Sulfur Recovery Unit Thermal Oxidizer vents, the Applicant used an emission factor necessarily based on long-term average process operation and then applied it to a one hour period. The Applicant calculated an emission rate of 114.2 pounds of sulfur dioxide per hour. The Draft Permit proposes to apply the 114.2 lb/hr rate to all four SRUs (as a bubble) that would operate at any given time. The Draft Permit also proposes a process throughput emission rate of 0.056 pounds of sulfur dioxide per long ton sulfur loaded to any single SRU process train.

However, the Applicant's determination of these short term sulfur dioxide rates and the SRU BACT for sulfur dioxide determination was carried out without regard to the inevitable occurrences of the process transient incidents identified in prior subsections and other reduced

[69] Plans which have the effect of a federally enforceable applicable requirement for the purposes of enforceability, environmental control and public notice and review must be incorporated into permits and public review processes. *See Waterkeeper Alliance, Inc. v. United States Environmental Protection Agency*, 399 F.3d 486, 494 (2nd Cir. 2005), amended 2005 US App LEXIS 6533 (Comprehensive Nutrient Management Plans which were not contained in NPDES permit provisions for concentrated animal feeding operations, not disclosed to the public, and never reviewed by the permit-issuing authority are not effluent limitations that assure compliance with the Clean Water Act).

process sulfur removal efficiency episodes. Given that such process operational transient emissions will occur, a proper BACT determination for short term Sulfur Recovery Unit Thermal Oxidizer SO_2 emissions must consider both physical process alternatives and the use of additional sulfur dioxide emission control devices.

The Applicant's BACT determination must be rejected on the grounds that the Applicant never carried out the needed short term SO_2 BACT demonstration or emission characterization from expected SRU sulfur transients. The SRU Thermal Oxidizer vents will never be able to comply with the Draft Permit SO_2 SRU emission limitations during such outages and transients. A permit to construct must not issue if the permit issuing authority knows that expected future operations and conditions known to occur with Claus/TTU process trains will render the owner/operator unable to comply with such a permit. Short- and long-term sulfur removal efficiency can be affected by intrusion of liquid petroleum hydrocarbons into sulfur recovery units, contamination-poisoning-deterioration of SRU process catalysts, and failure to maintain required process operational temperatures.

On reevaluation, the SO_2 BACT determination for the SRU must address process acid gas management in a more detailed manner. The analysis should address both sudden, unanticipated Claus Unit-TTU failures; the timing, duration and severity of total operational loss and reduced sulfur removal efficiency of Claus Units and Tailgas Treating Units; operational management methods addressing startup and shutdown of backup SRU capability; and management methods of acid gas diversion to other SRUs to address short term SRU process sulfur flow transients in any single SRU process train.

A sulfur dioxide-hydrogen sulfide-total reduced sulfur BACT reevaluation for the Sulfur Recovery Unit Thermal Oxidizer process train should ensure that management methods for altering the dispatch of acid gas for sulfur removal treatment following Claus Unit and/or Tailgas Treating Unit outages or malfunctions must be regarded as a BACT work practices to be memorialized in any permit issued as a federally enforceable emission limitation. Such work practice emission limitations require periodic monitoring, recordkeeping and reporting requirements as applicable permit provisions.

BACT work practice development cannot be delayed until after permit issuance because such a procedure violates the pre-construction review requirement for PSD BACT emission limitations and review. Such preconstruction review is also required to satisfy public review requirements discussed in the prior subsection.

8. *The Application's Sulfur Dioxide BACT Determination Does Not Properly Vet A Combination Of Claus Unit-Tailgas Treating Unit Sulfur Removal And Concomitant Use Of Wet Caustic Scrubbing As Required In A "Top-Down" BACT Review For Sulfur Dioxide And Hydrogen Sulfide Controls*

In carrying out a "top-down" BACT determination, various alternative configurations of potential process and emission control implementation must be reviewed. Failure to consider all feasible controls means that a proper "top-down" review has not been performed and the method does not provide assurance that the selected emission limitations actually constitute the required BACT stringency. In the case of the Sulfur Recovery Unit, the Applicant's SO_2 BACT demonstration never considered the technically feasible process-emission control configuration using a 99.7% efficient SRU train with Claus Unit and Tailgas Treating Unit, together with utilization of wet caustic scrubbing on the SRU Thermal Oxidizer exhaust.

The Applicant's SO_2 BACT determination for the SRU should not be approved until such a process-emission control configuration is reviewed.

9. *The Application's Particulate And Nitrogen Oxide Emission Characterization And BACT Demonstration For The Sulfur Recovery Unit Thermal Oxidizer Vent Stack Contains No Documentation Or Basis For The Emission Factors Selected*

The Applicant supplied Sulfur Recovery Unit Thermal Oxidizer particulate, PM_{10} and nitrogen oxide emissions saying:

> "This proposed emission limit is more stringent than any limit achieved by any petroleum refinery of which RTP is aware."[70]

The Applicant's BACT demonstration provided no other justification, background or basis for the PM, PM_{10} and NOx emission factors selected. As a result, there is no basis in the Application that can be used to verify the selected emission characterization. Similarly, because there is no way to verify and/or validate the PM, PM_{10} and NOx emissions, there is no basis or showing of how Applicant's BACT determination arrived at the final emission factors used. Such a failure means the Applicant failed to carry out the "top-down" BACT determination which the Applicant has claimed to use in their submittal.

The SRU Thermal Oxidizer BACT determination for PM, PM_{10} and NOx is further flawed because of the Applicant's erroneous claim that it was not possible to install any add-on emission control on the SRU Thermal Oxidizer vent stack exhaust. Notwithstanding the Applicant's claims, wet caustic scrubbing is technically feasible as PM/PM10 emission control (as well as control for SO_2 and TRS) and can further reduce condensible particle emissions because of wet scrubbing fuel gas cooling dynamics. The Applicant's BACT demonstration for PM/ PM_{10} should be rejected for failure to consider the technical feasibility of add-on wet caustic scrubbing to a 99.7% efficient Claus Unit/TTU SRU process train.[71] On reconsideration and re-review, costs for wet caustic scrubbing should be shared and apportioned between all of the NSR-regulated pollutants such a device would control when any economic analysis is performed for this control option alternative.

On the matter of NOx BACT review, the Application SRU Thermal Oxidizer NOx BACT demonstration failed to address the technical feasibility of 100% oxygen supply with precise input metering rather than use of air for oxidation, preventative methods for keeping

[70] The Application, at 74, Section 4.6.3.3; and at 75, Section 4.6.4.3.

[71] Commentors note that the Applicant did consider a wet scrubber, but only in combination with a Claus Plant with no Tailgas Treating Unit; this option was rejected because of excessive expected hydrogen sulfide emissions.

ammonia out of the Sulfur Recovery Unit and automatic SRU-Thermal Oxidizer process train distributed control systems.

10. *The Application Fails To Provide Certainty On Gas Collection And Emission Controls To Address Hydrogen Sulfide And Particulate Matter Emissions From Molten Sulfur Tank Storage And Molten Sulfur Product Loading*

The Applicant's process schematic diagrams for the Sulfur Recovery Plant and Sulfur Loading Facilities do not address any process gas collection system for controlling hydrogen sulfide and particulate matter associated with molten sulfur product storage, transfer and loading. Such operations are pollutant generating activities for which a PM, PM_{10}, $PM_{2.5}$, H_2S and TRS BACT demonstration and determination is required in a PSD permit.

The Applicant's statements about process gas collection from molten sulfur storage, transfer and loading contain inconsistent and vague information about this matter.

The BACT determination for the sulfur tanks discusses de-gassing of the liquid sulfur to a maximum hydrogen sulfide concentration of 15 parts per million by weight. While the degassing system is described as the BACT control for hydrogen sulfide, there is no mention in the H_2S BACT section for the sulfur tanks of collecting vapors from the tanks for control and/or flaring or incineration. However, the SRU description at Section 2.2.14 (p. 16) mentions these controls will be in place. If so, then they should have been mentioned in the BACT section and an appropriate emission limitation or design requirement be stated as a BACT H_2S control and fully required as a permit emission limitation.

If the H_2S concentration is 15 parts per million in de-gassed molten sulfur, then the maximum potential to emit for hydrogen sulfide emissions from molten sulfur tanks would be about 2.9 lbs/hr of hydrogen sulfide or 12.5 tons per year if the molten sulfur tanks will have atmospheric vents. This is greater than any hydrogen sulfide recognized by the Applicant in the Application and could pose some odor impact if the molten sulfur tanks have such atmospheric discharges. At this writing it isn't clear why the Applicant would discuss the molten sulfur de-gassing criteria as a BACT control if their intent was to merely vent the tanks back to the sulfur recovery process.

H. <u>The Application Fails To Make A Required BACT Determination For CO_2</u>

As noted above, a BACT determination must be made for "each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source...."[72] Carbon dioxide ("CO_2") is a pollutant which is currently regulated under the Clean Air Act. The proposed HEC will emit at least 19 million tons per year of carbon dioxide.[73] The proposed HEC is a major stationary source because it will be a petroleum refinery which has the potential to emit 100 or more tons per year of many regulated NSR pollutants, including carbon

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[72] 40 C.F.R. §52.21(12).

[73] *See* the Application, at Appendix H.

monoxide, nitrogen oxide, and sulfur dioxide.[74] Thus, the Draft Permit for the HEC cannot be issued unless it contains a BACT determination for CO_2.

1. *CO_2 Is A "Pollutant"*

Carbon dioxide is an air pollutant under the Clean Air Act.[75]

2. *CO_2 Is Regulated Under The Clean Air Act*

Carbon dioxide is regulated under numerous provisions of the Clean Air Act, including the new source performance standards for landfills under §11 of the Act; monitoring and reporting regulations under section §821 of the Act; the Clean Air Act State Implementation Plans of Delaware, Wisconsin and Michigan; pursuant to the Fiscal Year 2008 Consolidated Appropriations Act, H.R. 2764, Public Law 110-161 (Enacted Dec. 26, 2007); and through the issuance of Clean Air Act-required permits containing carbon dioxide emissions limitations which are enforceable under the Act.

Carbon dioxide is currently regulated under the new source performance standards for landfills under §11 of the Clean Air Act.[76] Carbon dioxide is a principal component of landfill gas.[77] Clean Air Act implementing regulations require that landfill gas emissions be controlled.[78] By regulating landfill gases under the Clean Air Act, EPA has necessarily regulated carbon dioxide under the Act. Any other conclusion is untenable.[79]

Carbon dioxide is also currently regulated under §821 of the Clean Air Act. Section 821, which was added to the Act as part of the 1990 Amendments,[80] provides that the EPA administrator must "promulgate any regulations...to require that all affected sources subject to

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[74] The Application, at 142.

[75] *See Massachusetts v. EPA*, 127 S.Ct 1438, 1443 (2007) ("greenhouse gases...fit well within the Clean Air Act's capacious definition of 'air pollutant.'").

[76] *See* 40 C.F.R. §§ 60.4248, 60.752, 63.6175, 63.6675.

[77] 40 C.F.R. §§ 60.4248, 63.6175, 63.6675 (defining landfill gas as "a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2").

[78] *See* 40 C.F.R. §60.752.

[79] *See* Petitioner's Reply Brief at 9, *In the Matter of: Northern Michigan University*, PSD Appeal 08-02 (E.A.B. Aug. 21, 2008).

[80] Despite EPA's allegations to the contrary, §821 is a part of the Clean Air Act. *See* Brief Amici Curiae of Utah and Western Non-Governmental Organizations at 8-9, *In re: Deseret Power Electric Cooperative*, PSD Appeal No. 07-03 (E.A.B. Feb. 8, 2008) (included as Attachment 1) and Supplemental Brief Amici Curiae of Utah and Western Non-Governmental Organizations at 1-18, *In re: Deseret Power Electric Cooperative*, PSD Appeal No. 07-03 (E.A.B. Sept. 12, 2008) (included as Attachment 2).

...the Clean Air Act shall also monitor carbon dioxide emissions...."[81] Pursuant to §821, the EPA issued several regulations in 1993 requiring the monitoring of CO_2 emissions (40 CFR §75.1(b); §75.10(a)(3) and §75.33), and the reporting of monitoring results for CO_2 and other pollutants to the EPA (40 CFR §75.60 - 64). Because monitoring and reporting requirements are regulations, *Buckley v. Valeo*, 424 US 1, 66-68 (1976), CO_2 is regulated under §821 of the Clean Air Act.

Carbon Dioxide is also regulated under the Clean Air Act through the State Implementation Plans ("SIPs") of Delaware and Wisconsin. In a Federal Register notice that went into effect on May 29, 2008, the EPA promulgated amendments to Delaware's SIP which include new regulations imposing CO_2 emissions limits on several classes of electricity generators.[82] Specifically, the regulations impose CO_2 emissions limits of 1,900 lbs per megawatt/hour (lbs/MWh) for existing distributed generators, 1,900 lbs/MWh for new distributed generators installed on or after January, 2008, and 1,650 lbs/MWh for new distributed generators that are installed on or after January 1, 2012.[83] Wisconsin's SIP also regulates CO_2 by imposing monitoring requirements on CO_2 emitters.[84]

EPA's approval of Wisconsin's SIP and Delaware's SIP revision integrated the CO_2 monitoring and control requirements into the states' respective implementation plans, which forms part of, and is enforceable under, the Clean Air Act.[85] The SIPs are an enforceable part of the Clean Air Act even if their standards exceed the minimum provisions needed to meet the Act's requirements.[86]

Carbon dioxide is also regulated under the Clean Air Act pursuant to the Fiscal Year 2008 Consolidated Appropriations Act, H.R. 2764, Public Law 110-161 (Enacted Dec. 26, 2007)

[81] 42 U.S.C. § 7651k note; Clean Air Act Amendments, 104 Stat. 2399 (1990).

[82] *See* Control of Stationary Generator Emissions, 73 Fed. Reg. 23,101 (April 29, 2008).

[83] *See* Delaware Department of Natural Resource and Environmental Control (DNREC), Regulation No. 1144: Control of Stationary Generator Emissions, § 3.2; *see also* Control of Stationary Generator Emissions, 73 Fed. Reg. 23,101, 23,102-103 (April, 29, 2008) (promulgating approval of these new regulations in 40 C.F.R. §52.420).

[84] *See* Wis. Admin. Code §NR 438.03(1)(a), adopted under the Clean Air Act at 40 C.F.R. § 52.2570(c)(70)(i); Wis. Admin. Code §NR 439.095(1)(f), adopted under the Act at 40 CFR § 52.2570(c)(73)(i)(l); 40 CFR §§ 60.33(c), 60.751 (defining 'landfill emissions'); Control of Landfill Gas Emissions from Existing Municipal Solid Waste Landfills, 63 Fed. Reg. 2154-01 (Jan. 14, 1998) (approving state plan for implementing landfill gas guidelines).

[85] *See Safe Air for Everyone v. EPA*, 475 F.3d 1096, 1105 "(holding that an EPA-approved state implementation plan has the 'force and effect of federal law' under the Clean Air Act"); 42 U.S.C. § 7602(q).

[86] *Sweat v. Hull*, 200 F.Supp.2d 1162, 1170 (D. Ariz. 2001) (holding that a SIP provision was subject to enforcement under the Clean Air Act even though it was not necessary to meet EPA's minimum standards).

("2008 Appropriations Act"). The 2008 Appropriations Act allocates a minimum of $3,500,000 to EPA to "develop and publish a draft rule not later than 9 months after the date of enactment of this Act, and a final rule not later than 18 months after the date of enactment of this Act, to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy."[87] The Conference Report on the 2008 Appropriations Act makes clear that EPA's authority to promulgate the rule derives from the Clean Air Act. The report specifies, "$3,500,000 within the Federal Support Air Quality Management program for the Agency to use its existing authority under the Clean Air Act to develop and publish a rule requiring mandatory reporting of greenhouse gas emissions above appropriate thresholds."[88] The Clean Air Act authority permitting EPA to promulgate the greenhouse gas reporting rule funded by the 2008 Appropriations Act necessarily extends beyond that provided by §821, because while §821 directs the EPA to set CO_2 monitoring and reporting requirements for coal-fired electricity generating plants, the 2008 Appropriations Act directs EPA to require greenhouse gas emissions reporting in "all sectors of the economy." Thus, EPA has "a separate and distinct statutory obligation to regulate CO_2" under the Clean Air Act.[89]

Finally, carbon dioxide is regulated under the Clean Air Act by means of permits containing CO_2 monitoring requirements which are enforceable under the Act. Numerous permits requiring the monitoring of CO_2 emissions have been issued.[90] While no final permit containing CO_2 monitoring requirements has yet been issued by DENR, the Big Stone I Title V Proposed Permit contains CO_2 monitoring requirements.[91] If the permit is made final, those monitoring requirements will be enforceable under the Clean Air Act.[92]

3. *CO_2 Is Subject To Regulation Under The Clean Air Act*

Even if CO_2 were not currently regulated under the Clean Air Act, CO_2 is still "subject to regulation under the Act" because EPA has the authority to regulate CO_2 emissions, but has refused to exercise that authority. Pollutants which are "subject to regulation" include not only those air pollutants for which emissions limitations have already been promulgated, but also those pollutants for which EPA has the authority to regulate, but has not done so. EPA itself, in

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[87] 2008 Consolidated Appropriations Act, H.R. 2764, 110th Cong., at 285 (2008).

[88] Conference Report on the 2008 Consolidated Appropriations Act, H.R. 2764, 110th Cong. at 1254 (2008).

[89] Petitioners' Supplemental Brief at 50-1, *In re Desert Rock Energy Company, LLC*, PSD Appeal Nos. 08-03, 08-04 (E.A.B. Oct. 7, 2008).

[90] *See e.g.* Permit for Campbell Plant p. 24, §VI.1, p. 42 § VI.1, p. 56 §1-3.6; Permit for Cobb Plant p.24 §VI.1, p. 27 § VI.1, p. 37 § VI.1, p. 54 §3.9.

[91] *See* Big Stone I Title V Proposed Permit at 21, § 8.4 (requiring monitoring of carbon dioxide emissions from two emissions units).

[92] 42 U.S.C. §§ 7413(a)(1) (authorizing enforcement for violations of any permit); (b)(providing for civil enforcement of any permit requirement).

the context of other environmental laws, has interpreted 'subject to' to mean polluting activity that 'should' be regulated, as opposed to polluting activity which is currently regulated.[93]

As the Supreme Court in *Massachusetts v. EPA* pointed out, CO_2 should be regulated under §202 of the Act unless EPA "determines that greenhouse gases do not contribute to climate change or if it provides some reasonable explanation...within defined statutory limits...as to why it cannot or will not exercise its discretion to determine whether they do."[94] EPA has failed to make any such determination, and its inaction is untenable in the face of overwhelming evidence that greenhouse gases such as CO_2 do contribute to global warming and that global warming "may reasonably be anticipated to endanger public health or welfare."[95]

4. *The HEC Facility Will Emit CO_2*

The proposed HEC will emit at least 19 million tons per year of carbon dioxide.[96]

5. *The Proposed HEC Is A Major Stationary Source*

A "major stationary source" includes any petroleum refinery which emits, or has the potential to emit, 100 tons per year or more of any regulated NSR pollutant."[97] The proposed HEC will be a petroleum refinery which has the potential to emit 100 or more tons per year of many regulated NSR pollutants, including carbon monoxide, nitrogen oxide, and sulfur dioxide.[98] Thus, the proposed HEC is a major stationary source.

Therefore, because the proposed HEC is a major stationary source which will emit the NSR-regulated pollutant carbon dioxide, a BACT determination must be made for each process unit in the HEC that will emit CO_2. Because the Applicant failed to make such BACT determinations, the proposed HEC may not be constructed.[99]

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[93] *See* Memorandum from Michael Shapiro, et al., Office of General Counsel to Waste Management Division Directors, "Interpretation of Industrial Wastewater Discharge Exclusion from the Definition of Solid Waste," at 2 (Feb. 17, 1995) (EPA has "consistently interpreted the language 'point sources subject to permits under [section 402 of the Clean Water Act]' the mean point sources that should have a [discharge] permit in place, whether in fact that do or not").

[94] *Massachusetts v. EPA*, 127 S.Ct. at 1444.

[95] 42 USC §7471(a)(1); *See also* Brief and Appendix of Amicus Curiae Climate Scientist Dr. James E. Hanson In Support of Petitioner, In re Deseret Power Electric Cooperative, PSD Appeal Nos. 07-03 (E.A.B. Jan. 31, 2008).

[96] *See* the Application, at Appendix H.

[97] 40 C.F.R. §52.21(b)(1)(i)(a).

[98] The Application, at 142.

[99] 42 U.S.C. § 7475(a)(4).

I. The Application Fails to Make A Required BACT Determination For NO_X

1. *The Application Fails To Consider Fuel Cleaning For Nitrogen As A BACT Method For NO_X Control*

A "top-down" BACT demonstration requires that all technically feasible controls for limiting emissions be listed and evaluated. For fuel combustion in a turbine with duct burners, the total source NO_X emissions are an artifact of the combined effect of thermal NO_X formation[100] and fuel-nitrogen oxidation.

The Application contains no information at all about the nitrogen content of any of the planned combustion turbine-duct burner fuels. The definition of BACT[101] requires that fuel cleaning be considered during all BACT determinations. Pre-combustion removal of nitrogen and nitrogen compounds from syngas and pressure swing tailgas are technically feasible physical-chemical processes of "gas cleanup" that must be addressed under the BACT definition and under EPA's "top-down" BACT determination procedure.

If there is no information at all in the Application on the nitrogen content of combustion turbine- duct burner fuels, then there has been no review or consideration as to whether fuel gas nitrogen cleanup has been assessed under the BACT determination procedure.

2. *The Application's BACT Demonstration Does Not Address Ultra Low NO_X Burners For The Turbine Duct Burners*

Although the Applicant apparently intends to include low NO_X burners for the 5 duct burner units, no quantification or evaluation was provided in the application addressing the duct burners. The Applicant should have at least stated the NO_X emission per heat input design basis for the duct burners, in order to evaluate the low NO_X burner claims in the submittal.

The duct burners should be evaluated for ultra low NO_X burners in addition to the low NO_X burners presently considered as a base control.

J. The Application's BACT Determinations Are Improper Because The Application Fails to Consider the Effects of Setting BACT Emission Limitations and Related Emission Control Systems on Unregulated Pollutant Emissions

In making a BACT determination, the "energy, environmental and economic impacts and other costs" resulting from the selection of particular control technologies must be taken into account.[102] The environmental impacts of a control technology decision which must be

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[100] Thermal NO_X formation results from high temperature reactions in the combustion zone between molecular nitrogen and oxygen.

[101] 40 C.F.R. §52.21(b)(12).
[102] 40 CFR §52.21(b)(12).

considered include not only the impacts associated with regulated pollutants, but also those associated with unregulated pollutants.[103]

The *North County* decision was the first time this doctrine on the BACT determination process was clearly articulated. In *North County*, citizen commentors appealed a decision of EPA Region IX on a proposed PSD permit for the North County Resource Recovery Associates, who proposed to construct a municipal waste combustor in California.[104] In a remand order back to EPA Region IX, then-EPA Administrator Lee Thomas wrote as to petitioner's allegations:

> "Among the reasons the petitioners present for granting review is Region IX's alleged failure to establish emission limitation for all pollutants, including hazardous pollutants, that will or could possibly be emitted from the facility; the alleged inadequacy of Best Available Control Technology (BACT) determinations....With one exception, Region IX has addressed each of petitioners' allegations and has provided rational explanations for not making any alterations in its permit determination.
>
> The exception concerns Region IX's assertion that EPA lacks the authority to "consider" pollutants not regulated by the Clean Air Act when making a PSD determination. This assertion is correct only if it is read narrowly to mean EPA lacks the authority to imposed limitations or other restrictions directly on the emission of unregulated pollutants. EPA clearly has no such authority over emissions of unregulated pollutants.
>
> Region IX's assertion is overly broad, however, if it is means as a limitation on EPA's authority to evaluate, for example, the environmental impact of unregulated pollutants in the course of making a BACT determination for the regulated pollutants. EPA's authority in that respect is clear....
>
> As defined in §169(3) the term BACT refers to an "emission limitation" that is set on a case-by-case basis for regulated pollutants, "taking into account energy, environmental, and economic impacts and other costs" associated with the particular emission control system that is selected to achieve the BACT emissions limitation. 42 USC §7479(3), (40 CFR §52.21(b)(12) (emphasis added).
>
> Hence, if application of a control system results directly in the release (or removal) of pollutants that are not currently regulated under the Act, the net environmental impact of such emissions is eligible for consideration in making the BACT determination. The analysis may take the form of comparing the incremental environmental impact of alternative emission control systems with the control system proposed as BACT; however, as in any BACT determination, the exact form of the analysis and the level of detail required will depend upon the facts of the individual case. Depending upon what weight is assigned to the environmental impact of a particular control system, the control

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[103] *See* EPA Administrative Decision In the Matter of North County Resource Recovery Associates, Remand Order, PSD Appeal No. 85-2, June 5, 1986 ("North County").

[104] *Id.*

system proposed as BACT may have to be modified or rejected in favor of another system.

In other words, EPA may ultimately choose more stringent emission limitations for a regulated pollutant than it would otherwise have chosen if setting such limitations would have the incremental benefit of restricting a hazardous but, as yet, unregulated pollutant."[105]

The precedent that PSD BACT determinations must consider the effects of control technology decisions on unregulated pollutants as part of the environmental impact analysis was extended and clarified in EPA's transitional guidance memo after the passage of the 1990 Clean Air Act Amendments.

"Toxic Effect of Unregulated Pollutants Still Considered in BACT Analysis -- Based on the remand decision on June 3, 1986 by the EPA Administrator in North County Resource Recovery Associates (PSD Appeal No. 85-2), the impact on emissions of other pollutants, including unregulated pollutants, must be taken into account in determining BACT for a regulated pollutant. When evaluating control technologies and their associated emissions limits, combustion practices, and related permit terms and conditions in a BACT proposal, the Applicant must consider the environmental impacts of all pollutants not regulated by PSD. Once a project is subject to BACT due to the emission of non-exempted pollutants, the BACT analysis should therefore consider all pollutants, including Title III hazardous air pollutants previously subject to PSD, in determining which control strategy is best."[106]

As such, both the Applicant and DENR must consider the effects of all control technology selections, options and the setting of emission standards for criteria pollutants on unregulated pollutants from this process.

In the case of the HEC, several needed BACT emission limitation determinations will have consequences for unregulated pollutants. For example, ammonia and odor emissions will be affected by control decisions for fugitive VOC emissions from process equipment component leaks. Control decisions for flares and pressure relief systems will have dramatic effects on odors and airborne toxicant emissions. However, neither the Applicant, nor DENR, carried out the required environmental impact review analysis for unregulated pollutant emissions under the PSD BACT definition and EPA's "top-down" BACT determination procedure.

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[105] *Id.* at 3-4.

[106] Memorandum from John S. Seitz, Office of Air Quality Planning and Standards, "New Source Review (NSR) Transitional Guidance" at 7 (Mar. 11, 1991), available at http://www.epa.gov/ttn/nsr/poly_gui.html.

VII. The Application's Air Quality Modeling Is Critically Flawed

A. The Application Must Show That Emissions From the HEC Will Not Exceed NAAQS Or Class II PSD Increments

DENR operates an authorized program under the PSD air permitting requirements of the Federal Clean Air Act and associated regulations at 40 C.F.R. §52.21, et seq. The Federal Act provides:

> "No major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless.....
>
> .....(3) the owner or operator of such facility demonstrates, as required pursuant to section 7410(j) of this title, that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of any (A) maximum allowable increase or maximum allowable concentration for any pollutant in any area to which this part applies more than one time per year, *(B) national ambient air quality standards in any air quality control region,* or (C) any other applicant emission standard or standard of performance under this chapter."[107] (emphasis added)

The Federal PSD regulations which DENR has adopted provide:

> "(k) *Source impact analysis.* The owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of:
>
> > (1) Any national ambient air quality standard in any air quality control region; or
> >
> > (2) Any applicable maximum allowable increase over the baseline concentration in any area."[108]

These requirements unambiguously require the Applicant to show that the proposed major emitting facility shall not jeopardize attainment and maintenance of any NAAQS and exceed (together with other PSD increment consuming sources) any Class II PSD increments shown at 40 C.F.R. §52.21(c).

In subsections below, Commentors address the air quality modeling demonstration submitted by the Applicant and the failure of this demonstration to make required showings under both the Act and PSD rules. Commentors review the Applicant's improper showings of NAAQS and increment consumption compliance, the Applicant's and DENR's improper background air pollution determination, the Applicant's improper use and implementation of air

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[107] 42 U.S.C. § 7475(a)(3).

[108] 40 C.F.R. § 52.21(k).

quality models, the Applicant's understatement of emission source term inputs used in air quality modeling demonstrations and DENR's failure to enforce required air quality modeling and ambient impact compliance determinations.

B. Air Quality Modeling Demonstrations Submitted Or Reviewed To Support Issuance Of A PSD Permit To A Major Stationary Source In South Dakota Must Conform To Approved South Dakota State Implementation Requirements Addressed At 40 C.F.R. Part 51, Appendix W

In considering and approving air quality modeling demonstrations submitted by the Applicant, DENR is bound by its adoption of federal air quality modeling requirements to use certain EPA-approved air quality models and modeling procedures and protocols. By virtue of adoption of Approved SIP Rule SD Code 74:36:09:02 (effective June 13, 2007), DENR adopted most of the federal PSD requirements at 40 C.F.R. §52.21, *et seq*. This approved State Implementation Rule adoption included 40 C.F.R. §52.21(l), which provides:

> "(l) *Air quality models.* (1) All estimates of ambient concentrations required under this paragraph shall be based on applicable air quality models, data bases, and other requirements specified in appendix W of part 51 of this chapter (Guideline on Air Quality Models).
>
> (2) Where an air quality model specified in appendix W of part 51 of this chapter (Guideline on Air Quality Models) is inappropriate, the model may be modified or another model substituted. Such a modification or substitution of a model may be made on a case-by-case basis or, where appropriate, on a generic basis for a specific state program. Written approval of the Administrator must be obtained for any modification or substitution. In addition, use of a modified or substituted model must be subject to notice and opportunity for public comment under procedures developed in accordance with paragraph (q) of this section."

In subsections below we show how the Applicant's air quality modeling demonstration fails to conform to 40 C.F.R. Part 51 - Appendix W requirements binding on DENR's permit issuance authority and determinations.

C. The Application's Air Quality Modeling For $PM_{2.5}$ Facility Impacts, Taken Together With The Appropriate $PM_{2.5}$ Background Concentration, Demonstrates The Facility Will Impermissibly Violate The 24 Hour $PM_{2.5}$ Primary, Health-Related National Ambient Air Quality Standard, Thus Rendering The Application Non-Approvable

The Applicant's Addendum 1 Air Dispersion Modeling report indicates a maximum 24-hour $PM_{2.5}$ impact of 11.30 micrograms per cubic meter.[109] Under the NAAQS compliance test requirements, this HEC impact must be added to the area's ambient air background concentration and the results compared to the NAAQS 24-hour $PM_{2.5}$ standard of 35 microgram per cubic

[109] Addendum 1, at 7, Air Dispersion Modeling and Class II Visibility Analysis for the Proposed HEC in Union County, Table 6-2.

meter for the 98th percentile monitored value as well as the NAAQS annual average $PM_{2.5}$ standard of 15 micrograms per cubic meter. Compliance with both the annual and 24 hour $PM_{2.5}$ standards is based on a three year average on air quality data for each averaging time.

Temporarily accepting the DENR decision to set the Sioux Falls, SD PM_{10} / $PM_{2.5}$ ambient monitor as the background site for purposes of discussion only,[110] Commentors review ambient air quality data for that monitor arranged in three year compliance evaluation periods in the table below:

Three Year Running Block Averages of the Annual 98th Percentile Value for the 24-Hour $PM_{2.5}$ Background Value for the Sioux Falls, SD $PM_{2.5}$ Ambient Air Quality Monitor and Combined Facility Impact			
24 Hour NAAQS Compliance Test Period	2005-2007	2004-2006	2003-2005
Hilltop Monitor Background Value (3 year average)	23.0	23.8	25.2
Facility Impact Plus Background Value	34.3	**35.1**	**36.5**

When considering the candidate three year block period for background purposes, the highest background concentrate indicated in the most recent five year planning window commensurate with the five years of air quality modeling should be selected as the background concentration. For the Hilltop monitoring site, the appropriate background concentration for air quality modeling and NAAQS compliance demonstration purposes is 25.2 micrograms per cubic meter for the 2003-2005 3 year compliance averaging period. When this 24 hour $PM_{2.5}$ background value is selected, the addition of the 11.3 microgram per cubic meter maximum 24 hour $PM_{2.5}$ facility impact shows that the 24 hour $PM_{2.5}$ NAAQS of 35 micrograms per cubic meter will be violated for two of the three compliance test periods during the five year evaluation period.

Because the new HEC ambient air quality impact plus the $PM_{2.5}$ background concentration exceeds the 24 hour $PM_{2.5}$ NAAQS standard, DENR must deny the Application since permit issuance would violate 40 C.F.R. §52.21(k)(1) and 42 U.S.C. §7475(a)(3).

DENR and the Applicant reach a different conclusion, but their finding about the Hilltop monitor site and its data as to determination of the ambient $PM_{2.5}$ background is in error and does not reflect a conservative approach to predicting the impact of the HEC on future air quality. DENR chose as a background value the year 2006 value which is among the lowest reported

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[110] Commentors wish to preserve our objection at all times that the Hilltop Monitor site at Sioux Falls, SD is not the most appropriate background monitoring site to evaluate the Applicant's air quality modeling demonstration.

values for the five year period. By choosing a single year's data as background, a facility's compliance with the 24 hour $PM_{2.5}$ NAAQS cannot be demonstrated for the full five year period of the air quality modeling demonstration. DENR has accepted the Applicant's flawed reliance on an understated 24 hour $PM_{2.5}$ background concentration and the Applicant's failure to demonstrate protection and maintenance of the 24 hour $PM_{2.5}$ NAAQS standard during a full five year modeling period. DENR's decision in doing so is clearly erroneous because DENR's action involves an erroneous determination of the background concentration, a failure to comply with PSD requirements and an allowance of a *de facto* process for the Applicant to impermissibly evade requirements for more stringently regulated facility emissions.

D. The Most Appropriate Background Site Monitor For Evaluation Of The Applicant's Future Compliance With $PM_{2.5}$ And PM_{10} NAAQS Is Located In Sioux City, IA

To carry out the required ambient air quality analysis for a PSD permit, the Applicant must develop background ambient air quality monitoring data from the most appropriate air quality ambient monitoring site to determine criteria pollutant background concentrations.[111] There are no ambient air quality monitoring sites very close to the proposed HEC site. Instead, the choice is between three regional $PM_{2.5}$ / PM_{10} ambient monitoring sites in the general area that are the candidate background sites. These air monitoring site locations are shown on a aerial photo/map in Attachment 3; they are the Hilltop site and Kelo site which are both in Sioux Falls, SD and the Sioux City, IA site.

The table below shows five years of $PM_{2.5}$ ambient air quality data from the three candidate air monitoring sites. The data shows that the Sioux City, IA site generally monitors the highest 24 hour and annual average $PM_{2.5}$ concentrations of the three candidate air monitoring sites.

Candidate $PM_{2.5}$ Air Quality Data for Background Concentration Evaluation – 2007-2003						
Monitor	Averaging Time	2007	2006	2005	2004	2003
Sioux City, IA Site	24 hr	31.2	29	25.2	21.9	29.0
	annual	10.64	10.33	10.62	9.45	10.84
Sioux Falls, SD Hilltop Site	24 hr	20.0	23.1	26.0	22.3	27.1
	annual	8.75	9.37	9.85	9.62	10.00
Sioux Falls, SD Kelo Site	24 hr	28.4	22.1	26.1	21.3	24.1
	annual	9.58	9.72	10.68	10.07	10.44
Note: $PM_{2.5}$ 24-hour values are the published 98th percentile value						

The Sioux City, IA $PM_{2.5}$ / PM_{10} monitoring site is the most appropriate site to use for determination of background concentrations at the HEC site. The Sioux City, IA site is the one which is closest to the proposed refinery site (about 25 miles away) and this site better

[111] *See* 40 C.F.R. § 51, at Appendix W, Section 8.2.

characterizes the urban plume downwind transport of $PM_{2.5}$ from the Omaha, NE urbanized area during southerly-sector winds on the HEC site. These same southern sector wind directions will also be the wind conditions typically occurring on the backward side of stagnating high pressure systems with expected long range transformation and transport of $PM_{2.5}$.

Characterization of the $PM_{2.5}$ background at the HEC site must address such transport from both near-field local urban transport (i.e. from urbanized Omaha, NE) and more distant locations (both near-field (i.e. IA, NE), as well as far-field (i.e. TX, LA, KS, OK). Such meso-transport together with other long range transport will contribute the largest single amounts of ambient $PM_{2.5}$ background as would be expected for the HEC. The relative positions of the HEC, all monitors, and the Omaha, NE area are shown in Attachment #4.

The advantage of the Sioux City, IA monitoring site over the Sioux Falls, SD sites is that the Sioux City, IA site would better represent near-field Omaha, NE urban plume transport in conjunction with the influences of long range transport on the HEC site than the Sioux Falls, SD site. The Sioux Falls, SD site is another 75+ miles further downwind from the Omaha, NE urban area during southerly wind conditions than the Sioux City, IA site. This means ambient $PM_{2.5}$ data at the Sioux Falls, SD site would represent a diminished or attenuated influence from Omaha, NE urban plume transport compared to the Sioux City, IA site.

The primary emphasis in decisions about selecting a regional monitoring site goes to the location and the representativeness of the data. In making a decision on which site will determine background no weight should be given to considerations that the monitoring site is, or is not, conducted by the permit-issuing authority. For characterizing $PM_{2.5}$ / PM_{10} background at the HEC site, the closer location of the Sioux City, IA site mitigates for its selection as the most representative regional monitoring site to reflect predominating HEC site background $PM_{2.5}$ / PM_{10}, rather than the Sioux Falls, SD site for background purposes.

E. In Making A Background Concentration Determination And In Conducting A Review To Determine Future Compliance With The $PM_{2.5}$ NAAQS, The Required Analysis Must Focus on Ensuring There is No Interference with Attainment and Maintenance of NAAQS for $PM_{2.5}$

In reviewing the effect of the proposed HEC on $PM_{2.5}$ air quality in an area presently in attainment, the Applicant and DENR must ensure that no NAAQS is jeopardized. If such jeopardy exists, the permit cannot issue under present circumstances because the pollutant emissions triggering such a concern must then be regulated with significantly more stringency that would be the case for a facility that does not jeopardize the NAAQS.

The requirement to ensure that a facility to be issued a PSD permit does not jeopardize any NAAQS standard is contained in the Clean Air Act[112] and in the EPA's New Source Regulations adopted by the State of South Dakota[113] and is articulated extensively in EPA's 1990

[112] 42 U.S.C. § 7410(a)(2)(D)(i)(I); 42 U.S.C. § 7475(a)(3).

[113] 40 C.F.R. § 52.21(k).

Draft New Source Review Manual. Longstanding practices widely used in state NSR programs throughout the United States generally require the use of latest five years of air quality data for a representative monitoring site to be evaluated in the determination of the background concentration. The EPA's PSD application checklist specifically mentions the need for five years of monitoring data.[114]

The fundamental purpose of collecting five years of air quality data is to ensure that any inherent air quality variability in background concentrations is considered in a conservative manner. DENR is under an obligation to ensure that the predicted air quality model impacts added to the pre-existing background concentrations will not result in ambient 24 hour or annual $PM_{2.5}$ concentrations exceeding the $PM_{2.5}$ NAAQS in any year. The only way to show this and take into account pre-existing background $PM_{2.5}$ concentration variability is to evaluate block three year averages occurring during the five year period and then to use the highest three year block average as a background value.

F. <u>DENR Understood That Use Of The Sioux City, IA Monitoring Site For Background Merited Serious Consideration, But Instead DENR Appears To Have Allowed The Applicant To Make The Final Decision On Which Background Site To Use</u>

The DENR Statement of Basis does not explain why the Sioux Falls, SD site was selected as the regional monitoring site instead of the Sioux City, IA site for background determination. However, the record indicates that DENR staff were fully aware of the Sioux City, IA $PM_{2.5}$ / PM_{10} site:

> "There are some discrepancies with the background data listed in the modeling protocol and DENR is unsure which year or years are used for the background data. The following Table should be used for Sioux Falls background data and is based on 2006 data." [table omitted, but shows 23 micrograms per cubic meter as $PM_{2.5}$ 24-hour (98th percentile) background]
>
> "**During our preliminary discussions, it was mentioned that originally you would use background data from Sioux City, Iowa and DENR suggested that you use Sioux Falls, South Dakota because it best represented air quality in that area**. However, if the model indicates high concentration levels are south of the project, **it might be advantageous to compare to both to alleviate any issues of why one background site was not used over the other**. If you decide to also use Sioux City's data, **DENR recommends that you use 2006 data.**"[115] (emphasis added)

This disclosure by DENR indicates a series of problems and regulatory failures on DENR's part in carrying out its PSD permit issuance authority.

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[114] *See* U.S. EPA, *Example Air Quality Analysis Checklist* (June 1978), available at http://www.epa.gov/scram001/guidance/guide/checklist.pdf.

[115] DENR, *Modeling Protocol Review*, at 2 (2007), available at http://www.state.sd.us/DENR/Hyperion/Air/2007DENRModelingResponse.pdf.

The first problem is that DENR said the Sioux Falls, SD site was more representative of the HEC site than the Sioux City, IA monitoring site for background, but DENR never justified or explained their decision. This is a critical air quality permit issuance finding that DENR must clarify as the public is owed an explanation for the background monitoring site decision.

The second problem indicated is that DENR did not determine or explain how a background concentration set on the basis of a single year's air monitoring results describes the worst case background condition for a five year modeling period. In fact, use of a single year as your criteria for determining background fails to make the appropriate demonstration of background air quality. The purpose of the PSD permit program is to ensure that air quality will not be degraded up to, or exceeding the level of the NAAQS standards. Selecting just a single year's monitoring results as a background value cannot ensure that a worst case background condition is actually considered when evaluating whether the air quality degradation from operation of the new source plus current background will not show a violation of a NAAQS standard during a five year modeling period. Selection of Year 2006 for ambient data background cannot be justified even as having the latest year available when available Year 2007 data was not used for the May, 2008 air quality modeling addendum submitted by the Applicant.

The third problem indicated with the DENR air quality modeling protocol approval decision is it shows DENR allowed the Applicant to make the decision about which site to use for background purposes for all practical purposes. The determination of the background monitor site as part of modeling protocol approval for a PSD permit-issuing authority is the duty of the agency and not for the Applicant.

G. Use Of Sioux City, IA Background Site Data Plus The Applicant's Assumed Maximum 24-Hour $PM_{2.5}$ Impact Shows Violations Of The 24-Hour Health-Related $PM_{2.5}$ National Ambient Air Quality Standard For All Block Three Year Averages Evaluated

As shown below, adding Applicant's modeled maximum 24-hour $PM_{2.5}$ ambient air quality impact from the HEC (11.3 micrograms per cubic meter) to the proper background $PM_{2.5}$ data from Sioux City, IA, reveals that the facility's emissions will violate the 24-hour $PM_{2.5}$ NAAQS for all block three year averages evaluated.

Three Year Running Block Averages of the Annual 98th Percentile Value for the 24-Hour $PM_{2.5}$ Background Value for the Sioux City, IA $PM_{2.5}$ Ambient Air Quality Monitor and Combined Facility Impact (micrograms per cubic meter)			
24 Hour NAAQS Compliance Test Period	2005-2007	2004-2006	2003-2005
Sioux City, IA Monitor Background Value (3 year average)	28.5	25.4	25.4
Facility Impact Plus Background Value	**39.8**	**36.7**	**36.7**

H. Given That Predicted Facility Impacts Plus Background Exceeds The 24-Hour $PM_{2.5}$ NAAQS Standard, DENR Cannot Issue The Permit

In previous sections, we show that the HEC will cause or contribute to 24 hour $PM_{2.5}$ NAAQS violations. Under such circumstances, DENR cannot issue the permit because such an action would be in violation of 40 C.F.R. §52.21(k)(1) and 42 U.S.C. §7475(a)(3). Furthermore, a facility located presently in an attainment area that is shown to cause or contribute to a predicted NAAQS violation cannot be permitted under PSD requirements. Instead, such a facility must be permitted under 40 C.F.R. § 51, Appendix S, Section III. The application does not make the required showings under this regulation.

I. The Application's Air Quality Modeling Results Seriously Understate Predicted Ambient Air Quality Impacts and Visibility Impact Because of Improper Application of Air Quality Models, Understatement of Emission Source Term Inputs to Air Quality Models and Through Use of an Outdated, Insufficient or Inappropriate Visibility Impact Modeling

1. *The Applicant's And DENR's Modeling Fail To Use A Domain Of Modeled Receptors With A Sufficient Spatial Extent To Properly Assess Ambient Air Quality Impacts From Both Elevated Sources At The HEC And From Cumulative Sources In The PSD Increment And NAAQS Analysis*

The purpose of air quality modeling is to render a fair depiction of the effects of emissions on ambient air quality. Air quality modelers must select a domain area including a sufficient spatial extent and placement of modeled receptor locations so that the maximum ambient air quality impacts can be detected and quantified during the modeling run. Such considerations have been incorporated into the planning and modeling requirements contained in Appendix W which is binding on air quality modeling activities and approvals carried out by DENR and on permit applicants such as HEC.

The appropriate selection of air quality modeling receptors has been addressed by U.S. EPA for use by PSD-authorized states:

"Critical Receptor Sites

> "a. Receptor sites for refined modeling should be utilized in sufficient detail to estimate the highest concentrations and possible violations of a NAAQS or a PSD increment. In designing a receptor network, the emphasis should be placed on receptor resolution and location, not total number of receptors. The selection of receptor sites should be a case-by-case determination taking into consideration the topography, the climatology, monitor sites, and the results of the initial screening procedure."[116]

The AERMOD modeling grid used by the Applicant covers an area with a radius of about 12 km around the proposed project.[117] DENR used a coarser grid that covers an even smaller area. Both of these modeling domain grids are too small to cover the maximum impacts from project sources with tall stacks and elevated plume rise such as flares. The AERMOD modeling grid should be extended to cover an area with a radius of 50 km. This 50-km radius is the maximum limit of applicability of this model. This larger modeling domain is also required to cover cumulative sources. Use of modeling domain with 50-km radius is frequent for properly conducted and implemented air quality modeling analysis. Because the Applicant's air quality modeling domain is not sufficiently large to describe critical receptors affected by both elevated HEC sources and other cumulative sources, the Permit Application should be deemed incomplete and not approvable.

2. *DENR And The Applicant Must Ensure That Emission Source Term Air Quality Model Inputs Properly State Maximum Expected Design Basis Or Maximum Allowable Emissions, Whichever Is Greater*

Binding provisions of 40 C.F.R. Part 51 - Appendix W provide clear requirements for the Applicant and DENR in carrying out air quality modeling and in formulating emission limitations in the Draft Permit. In particular, Appendix W Section 8.1 indicates that the design capacity or federally enforceable permit condition must serve for the modeling emission input data for NAAQS compliance demonstrations in PSD applications. The EPA NSR Workshop Manual requires that maximum allowable short-term emissions should be used for HEC sources, especially for intermittent sources that emit pollutants with short-term standards and/or PSD increments such as CO, PM_{10} and SO_2.[118] Higher short-term emissions will result in larger air quality and visibility impacts than those presented in the DENR Statement of Basis and the Application.

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[116] 40 C.F.R. § 51, Appendix W, Section 7.2.2.

[117] *See* the Application, at Appendix E, Figure 4-1 - HEC Receptor Grid.

[118] *See* U.S. EPA, *supra* note 48.

3. *The Application Understates Certain Short Term Air Quality Impacts Because Of The Use Of Annual Averaged Emissions For Source Term Inputs To Air Quality Modeling*

Commentors have previously discussed that certain portions of the Applicant's BACT analysis failed to provide appropriately determined short term emission rates and thus the BACT review did not follow the EPA "top-down" BACT Determination Process. Instead, the Applicant used annual averaged emissions to characterize the time rate of emissions for short term averaging times (1 hr, 3 hr, 24 hr).

The Applicant's air quality modeling demonstration cannot be approved because the Applicant's use of annual averaged emissions for short term emissions fails to ensure that the appropriately stated source term emission inputs are used in the Application's air quality modeling. The Applicant did not carry out all elements of the Appendix W Section 8.1.2 emissions characterization procedure. The practical effect of what the Applicant did was to underestimate expected short term emission rates for certain process equipment and emission units, since the determination of BACT-based emission rates for short term averaging times will sometimes be higher than what would be expected from a determination based on annual averaged emission rates. Use of annual averaged emissions for short term rates will thus lead to understated air quality modeling results for short term averaging times. This result is an improper application of the air quality modeling procedures to understate expected short term emissions.

In addition to using annual averaged emissions for short term rates for the modeling of HEC alone, the air quality modeling of cumulate sources for NAAQS and PSD increment consumption was also carried out using annual averaged emissions for short term emission rates. This means that the NAAQS and PSD air quality modeling results are also understated.

4. *The Application's Air Quality Modeling Understates Expected Ambient Impacts For $PM_{2.5}$ And PM_{10} Because Of Failures To Ensure That Modeled Emissions Include Condensible Particulate Matter*

Failure to include condensible particulate matter in $PM_{2.5}$ and PM_{10} air quality modeling results causes such modeling results to be understated, particularly when condensible particles are a significant percentage of total $PM_{2.5}$ and PM_{10} emissions. Once condensible particulate matter is emitted from a stack and flue gas containing condensible PM is cooled to ambient conditions, the solid particles and aerosols formed by such condensation may contribute to measured $PM_{2.5}$ and PM_{10} detected by using EPA Federal Reference Method ambient air quality monitoring. As a result, condensible particle emissions must be included in emission source term inputs to air quality modeling runs for $PM_{2.5}$ and PM_{10} performed in support of the Application. Because the Applicant failed to include all such condensible PM in the manner required in $PM_{2.5}$ and PM_{10} air quality modeling, the Applicant's air quality demonstration must be disallowed on such grounds and the Draft Permit must not issue until all such issues are resolved and there has been further opportunity for public comment.

Although EPA's Final $PM_{2.5}$ NSR rule[119] deregulated condensible emissions from major stationary source emissions calculus for purposes of major source status determination and netting analysis in the case of major modifications, nothing in that rulemaking altered the requirements for purposes of air quality modeling determinations of compliance with the $PM_{2.5}$ and PM_{10} NAAQS.

5. *The Application's Modeling Results For $PM_{2.5}$, PM_{10} And Visibility Impacts Do Not Consider Environmental Fate And Transport Of Emissions Resulting In Secondary Particle Formation During Physical-Chemical Conversion Under Atmospheric Influences*

The HEC's emissions of sulfur dioxide (863 t/y), nitrogen oxides (773 t/y), ammonia (273 t/y), hydrogen chloride (49 t/y), and sulfuric acid mist (80 t/y) will all participate in physical-chemical featuring particle formation and/or enhancement through either gas phase reactions forming particles (sulfuric acid, nitric acid, ammonium sulfate (or nitrate), ammonium chloride), or through physical particle formation through agglomeration and some condensation. Some reactions may happen in the near field and others will take more time in a downwind fetch from the HEC.

In order to properly determine visibility impacts of the HEC's emissions, secondary particle formation from physical-chemical atmospheric transport and transformation phenomena must be considered. The Application did not consider any physical-chemical secondary particle formation, either on downwind ambient concentrations or on visibility.

6. *The Application Understates Ambient Air Quality Impacts By Excluding Refinery Flare Emissions, Startup-Shutdown, Maintenance-Related And Malfunction-Related Emissions From Source Term Model Inputs*

The Application fails to characterize the maximum potential to emit for the five site refinery flares, except for pilot light emissions. Large flaring events may cause high emissions of sulfur dioxide and particulate matter during startup-shutdown and maintenance and malfunction-related events with site process equipment. The Applicant should have postulated worst case process scenarios leading to both acid gas and hydrocarbon flaring. These event postulates should have had emissions characterized and such emissions should have been modeled.

In addition to SO_2 emissions from flares, the Applicant never considered very high short term acid gas flaring during sulfur recovery unit outages from the SRU Thermal Oxidizers. The Applicant's failure to address the maximum flaring event or acid gas combustion scenario in determinations of sulfur dioxide, $PM_{2.5}$ and PM_{10} emissions means that the Applicant's air quality modeling demonstration understates expected air quality impacts for these pollutants. Such flaring events can be expected to cause heavy short term sulfur dioxide and particle emissions. Such emissions should be modeled to address short term impacts for the 3 hour and 24 hour sulfur dioxide NAAQS, the 24 hour PM_{10} and $PM_{2.5}$ NAAQS and for any corresponding

[119] *See* U.S. EPA, Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$), 73 Fed. Reg. 28,321 (May 16, 2008).

PSD increments.

7. *The Application May Understate Impacts On Compliance With The 24-Hour PM_{10} PSD Increment Because Of The Inadequate Spatial Extent Of The Domain Of Modeled Receptors*

Because the Applicant limited their modeling domain shown in the Application at Figure 4-1 in the air quality modeling report, PSD increment consuming sources outside of this area were excluded from the PSD increment consumption analysis for cumulative sources. The cumulative analysis only included sources passing a screening procedure known as the North Carolina D20 method.

The Applicant's air quality modeling prediction shown in Table 7-130 of the DENR Statement of Basis shows predicted results of 28.07 micrograms per cubic meter which is about 94% of the PSD Class II increment of 30 micrograms per cubic meter. The NAAQS and PSD increment consumption analysis for $PM_{2.5}$ and PM_{10} should be expanded to include all relevant sources in a 50-km radius grid. Inclusion of these omitted PM_{10} sources may lead to modeled exceedances of the 24- hour PM_{10} PSD Class II increment.

8. *The Application's Modeling Of Emissions From The Gasification Flare Stack Understates All Modeled Impacts From This Source Because Of Inappropriate Use Of Erroneous Stack Parameters*

When developing stack gas parameter inputs to the AERMOD model runs, the Applicant used an inappropriate stack gas velocity for the IGCC gasification flare stack that leads to understatement of the ambient impacts through of significant overestimation of the plume rise from the gasification flare. The Applicant used a stack gas velocity of 508.8 feet per second for this source. However, the proper method of developing flare stack inputs to air quality models is shown by the commonly used method to compute flare plume rise in the algorithm implemented in EPA's SCREEN3 model (USEPA, 1995). Developed by US EPA, this algorithm assumes an effective stack velocity of 20 meters per second and an effective exit temperature of 1273 degrees K. It then computes an effective stack diameter to account for reduced heat release. These effective stack parameters should then be used in AERMOD for a realistic treatment of flare plume rise.

We also note that a flare tip velocity of 508.8 meters per second would be precluded by source compliance with the flare design requirements at 40 C.F.R. §60.18(c)(3) & (4).

9. *The Application Significantly Understates Sulfur Dioxide Ambient Air Quality Impacts From The IGCC Plant Gasification Flare By Failing To Use The Maximum Sulfur Dioxide Short Term Emission Rates Expected As Indicated By The Application*

The AERMOD modeling for both annual and short-term (e.g. 1-hour, 3-hour and 24-hour) PSD Class II increment analysis and NAAQS compliance have used the same pollutant emissions for project sources. While this approach is justifiable for continuous sources, emissions from non-continuous or intermittent sources may be underestimated. A SO_2 emission rate of 15.729 lb/hr was used in modeling 3-hour, 24-hour and annual impacts of the IGCC Plant gasification flare. This emission rate is lower than the one calculated with the peak short-term flow rate of off-spec syngas of 1,500 MMBtu/hr.[120] With an emission factor of 0.02 lb/MMBtu, the peak short-term SO_2 emission rate is 30 lb/hr (1,500 MMBtu/hr x 0.02 lb/MMBtu). At 67% flaring, the SO_2 emission rate is 20 lb/hr. Both these emissions rates are higher than the modeled rate of 15.729 lb/hr. Thus, short-term concentrations and impacts from the flare are underestimated by up to 48%.

10. *The Application Fails To Model The Four Combustion Turbine-Duct Burner Stacks At The Maximum Allowable Sulfur Dioxide Emission Rate, Thus Understating The Sulfur Dioxide Ambient Air Quality Impacts From These Sources*

The AERMOD modeling for the combined gas cycle combustion turbines and duct burner combined stack used an emission total of 23.96 lb/hr (4 turbine-duct burner combinations x 5.99 lb/hr) for SO2 and 147.61 lb/hr (4 turbine-duct burner combinations x 36.9 lb/hr) for PM10. The modeled SO_2 emissions rate is much smaller than the allowable short-term emission rate of 42.3 lb/hr for SO_2 shown in Table 5.2.6 of the Application. Thus, the Applicant's air quality modeling of the four combustion turbine-duct burner vent stack understates short-term sulfur dioxide ambient air quality impacts from each of the four stacks in both the NAAQS and PSD increment consumption analysis by using a SO_2 emission source term of only 0.56 times what is actually allowable under the Draft Permit emission limitations.

11. *Project 24-Hour $PM_{2.5}$ Impacts Will Exceed The Proposed 24-Hour PSD Class II Increment*

Table 7-127 of the DENR Statement of Basis reports a modeled $PM_{2.5}$ 24-hour concentration of 11.3 ug/m3 from HEC emissions alone. This 24-hour concentration will exceed the $PM_{2.5}$ 24-hour PSD Class II increment of 9 ug/m3 that has been recently proposed by the US EPA on September 21, 2007.[121]

12. *The Application Uses An Obsolete Model During Plume Blight Impact Determination*

Significant visibility impacts at PSD Class II areas have been calculated by the VISCREEN model that implements the screening Level I recommended by the U.S. EPA. As a refinement, the PLUVUE II model was then used to analyze plume blight impacts. The PLUVUE II model uses a Gaussian plume dispersion similar to the ISC3 model which has been replaced by the AERMOD model since December 2006. Thus, the dispersion submodel of PLUVUE II is considered to be obsolete.

[120] *See* email from Colin Campbell, RTP Environmental to Kyrik Rombough, DENR (Aug. 12, 2008), available at http://www.state.sd.us/DENR/Hyperion/Air/20080812IGCCFlareEmail.pdf.

[121] Prevention of Significant Deterioration (PSD) for Particulate Matter less than 2.5 micrometers ($PM_{2.5}$), 72 Fed. Reg. 54,112 (Sept. 21, 2007).

13. *The Application's Viscreen Analysis Severely Underestimated Visibility Impact*

The Application's Viscreen analysis assumed no sulfates (SO_4). This is the same as assuming no SO_2 emissions from PCAEC, because all SO_2 are assumed to be fully converted to sulfates (SO_4) in a screening analysis. Thus, visibility impacts are severely underestimated. As a tool for screening analysis of plume blight impacts, the Viscreen model requires emission inputs to be representative of a worst day. A PM_{10} emission rate of 237 lb/hr was inputted to Viscreen. On an annual basis, this emission rate is equivalent to 1,038 tpy (237 x 8760/2000). This annual emission rate is slightly less than the total facility-wide emissions of 1,046 tpy.

14. *Screening Visibility Analysis Has Severely Underestimated Plume Blight Impacts*

Notwithstanding the misapplication of the Viscreen model as presented in another comment in this subsection, plume blight impacts at the modeled National Park Service facilities have also been severely underestimated by omitting SO_2 emissions. Under normal operating conditions, the HEC will emit a total of 863 tpy that results in an hourly-averaged SO_2 emission rate of 197.03 lb/hr. This hourly rate should be inputted to Viscreen since normally all SO_2 emissions are assumed to be converted to SO_4 in a screening analysis. Emissions inputs to Viscreen should also represent a worst day and, for SO_2, they should include flaring emissions under upset conditions. Thus, by omitting SO_4, the Viscreen analysis has severely underestimated the plume blight impacts of PCAEC.

15. *Plume Blight Impacts Have Been Improperly Analyzed with the Level 1 Analysis for Receptors Located Beyond 50 Km from the HEC*

The Viscreen model has been used in a Level 1 screening analysis at the following National Park Service facilities: Homestead National Monument (167 km from the HEC), Lewis & Clark National Historic Trail (106 km from the HEC), Niobrara National Scenic River (101 km from the HEC) and Pipestone National Monument (93 km from the HEC). Based on the Gaussian plume formulation, the Viscreen is applicable to visibility analysis for receptors located within 50 km of the proposed project. In addition, the screening analysis assumed low wind speed and stable conditions (F stability and 1 m/s wind). At this speed, it would take the HEC plume about 25 hours to reach the receptor areas. It is unreasonable to assume that such low wind, stable condition will last for a whole day. It is also unlikely that the plume will reach these receptors intact because of high shear under stable conditions. For these reasons, National Park Service has recommended the Viscreen model only for screening analysis for receptors located within 50 km of the project (FLAG, 2000). A more appropriate model is the Calpuff model which has been recommended by US EPA for dispersion modeling and visibility analysis beyond 50 km (US EPA, 2005).

J. <u>Far-Field Modeling On Air Quality And Visibility Impacts At PSD Class I Areas Should Be Performed With A Photochemical Grid Model</u>

A modeling analysis of air quality and visibility impacts at mandatory PSD Class I areas such as Badlands National Park, Wind Cave National Park and Theodore Roosevelt National

Park was not performed in the Application. The reason given in the Application is that these PSD Class I areas are located more than 300 km away from the HEC. This 300 km distance is the limit of applicability of the Calpuff model. There are photochemical grid models such as CMAQ and CAMx that can be used to assess potential impacts beyond 300 km. South Dakota is part of the Western Regional Air Partnership ("WRAP"). In recent years, WRAP and the neighboring CENRAP (Central Regional Air Planning Association) have extensively applied these photochemical models to regional ozone, in $PM_{2.5}$ and visibility studies.

Neighboring states such as Iowa and Nebraska and other states (Kansas and Texas) have used the CAMx model for BART assessment. The primary reason for these states in deciding to use the CAMx model is that the power plants are located more than 300 km from PSD Class I areas. Thus, the Application should include a CMAQ/CAMx modeling analysis of potential air quality and visibility impacts of the HEC at PSD Class I areas.

K. Project Impacts On Ozone Air Quality Have Not Been Addressed

The proposed HEC will emit large amounts of NO_x (773 tpy) and VOC (473 tpy). Known to be ozone precursors, these pollutants react under sunlight to form ozone. The Application has not addressed their impacts against the 8-hour ozone standard. US EPA has recently lowered the 8-hour standard from 0.08 ppm to 0.075 ppm. Ozone modeling should be performed to assess the impacts of project emissions on ozone air quality in Union County and other nearby areas.

VIII. The Application's Analysis Of Air Impacts Of Hazardous Air Pollutants ("HAPs") And The Health Risks Resulting From HAPs Are Inadequate

A. Project Cancer Risks Have Been Underestimated By Omitting Non-Inhalation Risks

The HEC will emit several toxic chemicals that are known to be carcinogens. A screening level analysis has been performed by Environmental Resources Management in April 2008 using the HEM-3 model (ERM, 2008). However, this analysis only considers selected equipment that emit arsenic, benzene, cadmium, chromium, formaldehyde, naphthalene, nickel, POM and 1,3-butadiene. This analysis only focuses on inhalation risk and, hence, understates potential health effects by ignoring non-inhalation risks such as ingestion of soil, drinking water and food. Non-inhalation risks from multipathway pollutants such as arsenic are several times larger than inhalation risks. In its screening risk assessment guidelines, South Coast Air Quality Management District has recommended multiplying factors of 4.78 and 29.76 to account for non-inhalation risks for arsenic and PAH, respectively (SCAQMD, 2008). Using the risk estimates in the ERM screening analysis (Tables 3-1 and 3-2 for cancer risks of arsenic and benzene including Census block 1034), cancer risks from arsenic are estimated in the table below for both scenarios (high end and low end) of unit risk factors (URF) for benzene. Multiplying the estimated arsenic cancer risks by the 4.78 factor recommended by SCAQMD, the adjusted cancer risks from arsenic alone are above 1 in 1 million for both scenarios. The total adjusted cancer risks, from both arsenic and benzene, are 2.33 and 1.91 in 1 million for the high end scenario and the low end scenario, respectively. For both scenarios, the total adjusted risks are above the acceptable limit of 1 in 1 million set by EPA in September 2007 for the benzene NESHAP (ERM page 17).

Scenario for Benzene URF	Risk of Arsenic & Benzene	Risk of Benzene	Risk of Arsenic	Adjusted Risk of Arsenic	Total Adjusted Risk
Higher End	9.41E-7	5.72E-7	3.69E-7	1.76E-6	2.33E-6
Lower End	5.28E-7	1.61E-7	3.67E-7	1.75E-6	1.91E-6

Notes:
(a) Risks of arsenic and benzene and risk of benzene taken from Tables 3-1 and 3-2 (ERM,2008).
(b) Risk of arsenic = risk of arsenic and benzene – risk of benzene
(c) Adjusted risk of arsenic = 4.78 * risk of arsenic
(d) Total adjusted risk = adjusted risk of arsenic + risk of benzene

Thus, the screening analysis in the Application severely underestimates the HEC cancer risks by not considering the non-inhalation health risks. A full health risk assessment will need to be conducted to assess potential health effects of the toxic chemicals emitted by the HEC as part of public health and environmental justice concerns. AMI Environmental ("AMI") has developed a model named ACEHWCF (Assessment of Chemical Exposure for Hazardous Waste Facilities) that can evaluate both inhalation and non-inhalation risks using the multipathway exposure algorithms recommended by the U.S. EPA.[122] [123]

B. Project Noncancer Acute And Chronic Health Effects Have Not Been Quantified

The HEC will emit several toxic chemicals that are known to cause noncancer acute and chronic health effects. The screening analysis with the HEM-3 model performed as part of the Application only considers the cancer risks from inhalation alone. Toxics such as arsenic and benzene are also known to cause noncancer health effects due to chronic exposure. As shown in the Application, the HEC will also emit large amounts of toxics with acute health effects such as ammonia (273 tpy), hydrogen chloride (49 tpy) and hydrogen sulfide (25 tpy). Noncancer health effects of all these substances have been omitted in the screening analysis. Thus, noncancer health effects should be quantified by calculating hazard quotients for acute and chronic exposure. Chronic health effects should also include non-inhalation risks such as ingestion of soil, drinking water and food. As described above, the ACEHWCF model developed by AMI can be used to estimate the noncancer health effects of toxics emitted by the HEC.

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[122] U.S. EPA, *Human Health Risk Assessment Protocol for Hazardous Waste Facilities, Final,* (September 2005).

[123] The ACEHWCF model has been described in a technical paper: Khanh T. Tran, *ACEHWCF – A Comprehensive Risk Assessment Model for Hazardous Waste Combustion Facilities* (2001), available at http://www.amiace.com/acehwcf_paper.pdf.

IX. The Application's Soil And Vegetation And Visibility Analyses Are Deficient[124]

A. Class 1 Visibility Impacts Are Not Properly Addressed

A modeling analysis of air quality and visibility impacts at mandatory PSD Class I areas such as Badlands National Park, Wind Cave National Park and Theodore Roosevelt National Park was not performed in the Application. The reason given in the Application is that these PSD Class I areas are located more than 300 km away from the HEC. This 300 km distance is the limit of applicability of the Calpuff model. There are photochemical grid models such as CMAQ and CAMx that can be used to assess potential impacts beyond 300 km. South Dakota is part of the Western Regional Air Partnership (WRAP). In recent years, WRAP and the neighboring CENRAP (Central Regional Air Planning Association) have extensively applied these photochemical models to regional ozone, in PM2.5 and visibility studies. Neighboring states such as Iowa and Nebraska and other states (Kansas and Texas) have used the CAMx model for BART assessment. The primary reason for these states in deciding to use the CAMx model is that the power plants are located more than 300 km from PSD Class I areas. Thus, the Application should include a CMAQ/CAMx modeling analysis of potential air quality and visibility impacts of the HEC at PSD Class I areas.

B. The Application's Soil And Vegetation Analysis Is Improper Because Project Ozone Impacts On Sensitive Crops And Plants Have Not Been Analyzed

Ozone is a secondary pollutant that is formed under sunlight from precursors NOx and VOC. Similar to sulfur dioxide, several plant species are affected by ozone. The HEC will emit large amounts of NO_x (773 tpy) and VOC (473 tpy). The Application has not presented an impact analysis of either ozone or VOC as a surrogate. US EPA has recommended VOC screening levels of 392 ug/m3 (1-hour), 196 ug/m3 (4-hour) and 118 ug/m3 (8-hour). It should be noted that these screening levels were based on studies in the 1970s and may not be protective of crops and plants in the area around the HEC.

X. The Application Fails To Comply With South Dakota Odor Nuisance Law

A. DENR Must Address Odor Nuisance As Pollution

South Dakota air pollution law addresses odors and their effect in the following manner:

"Definition of terms. Terms used in this chapter mean:

> (1) "Air contaminant," dust, fumes, mist, smoke, other particulate matter, vapor, gas, odorous substances, radioactive materials as defined in chapter 34-21, or any combination thereof;
>
> (2) "Air pollution," the presence in the outdoor atmosphere of one or more air contaminants in such quantities and duration as is or tend to be injurious to human health or welfare, animals or plant life, or property, or would interfere with the

[124] *See* CAA § 165(e)(3), 42 U.S.C. § 7475(e)(3)(b); *see also* 40 CFR § 52.21(o).

enjoyment of life or property;"[125]

The DENR air pollution statute is both remedial and anticipatory in nature. In conducting an air permit new source review, DENR as the permit issuance authority, must determine what types and how much air pollution will be emitted by a source.

The above definition of air pollution recognizes such pollution can become injurious to the "....public....welfare.....[and]...property.." when "*quantities and duration*" of such pollution become "*injurious*" and when emissions "... *would* interfere with the enjoyment of life or property...." The use of the word "would" in the preceding phrases indicates a legislative intent to create an anticipatory duty for a decision maker under the statute.

In determining the duties of DENR as permit-issuing authority, the South Dakota air pollution statute must also be read together with other state authorities binding on DENR permit issuance decision-making concerning nuisance, environmental protection and protection of the public trust in air resources of the state.

The South Dakota "Remedies Against Nuisance" statute must also be considered; the Act provides a definition of nuisance:

> "Acts and omissions constituting nuisances. A nuisance consists in unlawfully doing an act, or omitting to perform a duty, which act or omission either:
>
> (1) Annoys, injures, or endangers the comfort, repose, health, or safety of others;
> (2) Offends decency;
> (3) Unlawfully interferes with, obstructs, or tends to obstruct, or renders dangerous for passage, any lake or navigable river, bay, stream, canal, or basin, or any public park, square, street, or highway;
> (4) In any way renders other persons insecure in life, or in the use of property."[126]

In addressing the regulation of odorous emissions within the meaning the South Dakota air pollution statute, no conduct must be authorized by permit decision of DENR as state officers that would create a nuisance as defined by the Remedies Against Nuisance statutory provisions above.

The South Dakota Remedies Against Nuisance statute also provides the following defensive shield:

> "Acts under statutory authority not deemed nuisance. Nothing which is done or maintained under the express authority of a statute can be deemed a nuisance."[127]

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[125] *S.D. Codified Laws § 34A-1-2.*

[126] *S.D. Codified Laws § 21-10-1.*
[127] *S.D. Codified Laws §21-10-2.*

In enacting this section, the Legislature must have intended that state officers issuing a facility construction permit would be prevented from knowingly or negligently creating a situation in which allows emissions would create a nuisance as defined at SDCL §21-10-1. Otherwise, there would be no point to providing a remedial statute to protect its citizens and communities against nuisance conditions. Furthermore, the effect of the SDCL §21-10-2 provision could not be understood to be an unconstitutional non-rebutable presumption that no nuisance could exist merely because of the facility's status as one that has obtained an air discharge permit from DENR and thus were to be construed as operating under authority of a South Dakota statute.

The South Dakota Environmental Protection Act[128] provides binding procedural and substantive requirements concerning the decision-making process of DENR permit issuance, including decisions on provisions of the Draft Permit:

> "Detrimental conduct prohibited when reasonable alternative available. In any such administrative, licensing, or other proceedings, as described in § 34A-10-2, and in any judicial review thereof, *any alleged pollution, impairment, or destruction of the air, water, or other natural resources or the public trust therein, shall be determined*, and *no conduct shall be authorized or approved which does, or is likely to have such effect* so long as there is a *feasible and prudent alternative* consistent with the *reasonable requirements of the public health, safety, and welfare*."[129] (emphasis added)
>
> "Affirmative defense of no reasonable alternative--Burden of proof and weight of evidence. The defendant may also show, by way of an affirmative defense, that there is no feasible and prudent alternative to defendant's conduct and that such conduct is consistent with the promotion of the public health, safety, and welfare in light of the *state's paramount concern for the protection of its natural resources from pollution, impairment, or destruction*. Except as to the affirmative defense, the principles of burden of proof and weight of the evidence generally applicable in civil actions in the circuit courts shall apply to actions brought under this chapter."[130] (emphasis added)

Thus, the South Dakota Environmental Protection Act provisions cited above (when read together with provisions of the air pollution and nuisance statutes) require the following as to DENR decision-making and the HEC air discharge permit application.

DENR must ensure that its air discharge permit issuance decision conforms to the decision-making procedural standards of §34A-10-8 by determining odor emissions and neighborhood odor impacts under the requirement to determine "pollution, impairment and destruction" of air resources. Both the emission of odors from stack and fugitive sources at the

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[128] *S.D. Codified Laws §§ 34A-10, et seq.*

[129] *S.D. Codified Laws § 34A-10-8.*

[130] *S.D. Codified Laws § 34A-10-10.*

proposed facility and the ambient odors actually expected to be present in adjacent neighboring receptor sites outside the facility fence-line must be addressed. Odor emissions from stacks, vents and fugitive sources and odor ambient impacts outside facility fence lines are germane to an inquiry on pollution emissions, impairment and destruction conditions reflecting the ambient presence of odors outside the facility.

DENR must address odor emissions and impacts from the proposed refinery in an anticipatory and preventative manner since the statutory definition of air pollution and air contamination clearly countenance prospective determination of whether odors rising to air pollution will occur. DENR cannot simply ignore the odor issue during air permitting and then seek remedies after the fact of the facility's construction and operation. The expectation of the South Dakota Legislature in enacting the air pollution act, the nuisance law and the environmental protection law was that DENR would act in a preventative manner to ensure that conduct authorized under a lawfully issued air discharge permit does not result in a nuisance and in air pollution.

DENR must give weight to the public's trust in air resources of the State of South Dakota under SDCL §34A-10-8 when determining allowable emissions from the HEC. Under the public trust doctrine, the HEC cannot emit odor air contaminants in a manner and so as to dominate the use of available air resources through its odor emissions because no entity can utilize a public trust in a manner that the use of those resources by others is impaired or destroyed. DENR as permit issuing authority must take primary responsibility for managing odor air contaminant sources such as the HEC so the public trust is protected.

B. Petroleum Refineries And Facility Processes Managing Sulfur Are Known Sources of Community Odor Air Pollution

There is a long history of petroleum refineries causing odor complaints by neighbors at several sites in the United States. Petroleum refinery process equipment release odors from both stack vent and fugitive emission sources. The origin of these odors in the refinery process involve emissions of sulfur compounds, VOCs and oily particles or aerosols.

The following chemical emissions are odors known to be released from refinery process equipment that may cause downwind odor nuisance:

Hydrogen sulfide
Methyl mercaptan
Dimethyl Sulfide
Other reduced sulfur compounds (COS, CS2, DMDS, other mercaptans, etc.)
Sulfur dioxide
Gasoline vapor
Ammonia
Volatile organic compounds

Odor thresholds for hydrogen sulfide and mercaptan compounds are extremely low. NAAQS for sulfur dioxide only limit sulfur dioxide ambient concentrations on a 24 hour basis. As a result, ambient modeling that focuses on the 24 hour averaging time of the NAAQS standard cannot address sulfur dioxide concentrations with short term averaging times (i.e. minute to ten minutes to an hour) of significant to odor impact determinations.

Process equipment and production materials at the subject facility will release one or more of the above odor air contaminants and include:

Hydrogen sulfide from the IGCC gasification CO2 vent;

Hydrogen sulfide, other TRS compounds and VOCs from refinery component leak fugitive emissions;

Fugitive emissions of hydrogen sulfide, methyl mercaptan, carbon disulfide and carbonyl sulfide from sulfur recovery plants and tailgas treater fugitive emissions and products of incomplete combustion;

Hydrogen sulfide, TRS and ammonia from refinery sour water management, treatment and storage system;

Hydrogen sulfide, TRS, sulfur oxides and volatile organic compounds from refinery flare operation, including products of incomplete open air flair combustion;

VOCs and Fumes from crude oil, petroleum naphtha, intermediate and product tanks, spills, product loading racks and petroleum wastewater sewers;

Asphalt fumes from heated asphalt storage tanks;

Sulfur oxide emissions from petroleum refinery heaters; and

Products of incomplete combustion from refinery wastewater equipment fugitive gas collection and incineration equipment, and wastewater-related fugitive emissions, including fugitive VOC from refinery sludge handling.

DENR either is, or should be, aware of petroleum refineries as being important sources of odors requiring significant evaluation and attention in air permitting to avoid causing odor nuisances to adjacent communities.

C. Neither The Application Nor DENR's Statement Of Basis Contain An Acceptable Determination Of What Odor Emissions Will Occur, Of The Environmental Acceptability For Such Odor Air Contaminant Emissions Or Of The Community Of Neighbors To The Planned Site As Individuals Affected By Odor Air Pollution

1. *The Application Fails To Characterize Emissions Of Methyl Mercaptan And Other Reduced Sulfur Compounds Other Than Hydrogen Sulfide*

The Application contains no information at all on methyl mercaptan emissions which are known to occur from petroleum refineries and post significant risks of unacceptable community odor nuisances. There is no identification and quantification of methyl mercaptan, carbonyl sulfide and carbon disulfide from refinery sulfur recovery units and tailgas treatment units. Merely equating total reduced sulfur emissions to hydrogen sulfide emissions does not characterize important mercaptan effects on community odors distinct from hydrogen sulfide.

2. *The Application Fails To Include A Demonstration Of Community Odor Environmental Acceptability For Allowable Emissions Of Odorous Air Contaminants*

Nothing in the Application contains any air quality modeling or environmental acceptability demonstration for the planned process equipment and the anticipated odor air contaminant emissions. While the Applicant did characterize hydrogen sulfide, sulfur dioxide and ammonia emissions from some (not all) of its process equipment, nothing in the Application contains or displays any demonstration of the environmental acceptability of planned odor air contaminant emissions as they would impact the HEC's neighbors.

There is no air quality modeling demonstration to examine the effects of allowable odor air contaminant emissions on ambient downwind concentrations of odor pollutants. There are also no comparisons of any such predicted ambient concentrations to odor thresholds for the pollutants under consideration for the short averaging times relevant to odor perception. There is no analysis depiction of odor impact roses for predicted ambient impacts displayed in a manner to show the relationship between odor concentrations and wind speed and direction origination direction sectors. Nothing explains what proportion of the time refinery neighbors will have detectable and objectionable odors from refinery odor emissions.

Commentors are fully aware that the mere receptor experience of an odor occurrence, in and of itself, doesn't rise to the character of prohibited nuisance. Such prohibited nuisance conduct means that odorous pollutants are anticipated to occur in neighborhoods beyond the fence-line with a frequency, duration and intensity that, taken together and considered on a case by case basis, achieve a level of nuisance defined by the South Dakota air pollution statute and the general nuisance statute, and a level of effect on air resources reflecting "pollution, impairment and destruction" from odorous emissions.

The types of analysis mentioned in preceding paragraphs of this subsection are necessary to make an anticipatory determination of odor impact and review of preventative odorous emission controls. Nothing at all in the Application or in DENR's Statement of Basis is a finding as to whether or not the HEC's odor emissions will cause pollution, odor nuisance and impairment and destruction of community air resources at the many neighboring and fence-line receptor sites. Under the South Dakota Environmental Protection Act, DENR must make such a required finding as to odorous pollutant emissions from the HEC.

3. *The DENR Decision To Issue A Draft Permit Has Taken Place Under A Condition Of Deliberate And Negligent Indifference To Information About The HEC Site Neighboring Community And The Effects Of The HEC's Odorous Emissions On This Neighborhood And The People Living Close To The Site*

Evaluation of the effects of odorous emissions on a neighboring community requires permit applicants and permit-issuing authorities to gain an understanding of neighboring communities and critical receptor sites outside of the facility fence-line. Existing DENR air permit application requirements recognize the need in such applications to address community and neighborhood impacts.

Under the directions of the DENR application form submitted by the Applicant, an air permit application must include a specific map for a stationary source:

> "For stationary sources only, please enclose a map or a drawing showing roadways, location of plant and the nearest residents in each direction from the source. Include other structures which may be affected."[131]

The only map which might be evaluated on this matter is Figure 2-2 on p. 5 of the air quality modeling study submitted by the Applicant.[132] Applicant's submittal indicates that:

> "A regional map showing the project site is presented in Figure 1.2-1. More detailed information regarding the project site is presented in Appendix C to this permit application."[133]

However, Appendix C contains nothing but emission table spreadsheets and does not address the information claimed on page 5 of the Application. Figure 2-2 does not show the neighbors to the facility as is required by the terms of the DENR air permit application form.

A proper assessment of the neighborhood receptor sites for purposes of odorous emission impact review would identify any schools, daycare centers, parks and recreation areas, health and medical facilities, retirement housing and other critical land uses potentially affected by odorous emissions. No information of this nature was submitted by the Applicant.

Notwithstanding the failure of the Applicant to submit the required site-neighborhood map under DENR application requirements, DENR nevertheless approved the Application as complete. Such a failure illustrates DENR's negligent review through its failures to consider neighbor hood information and failure to determine odorous emission impacts.

In fact, the area around the HEC is not isolated and this area contains many nearby structures. Commentors provide Attachment 5, which shows the area around the HEC using Google Earth.[134] The external and internal corners of the approximate boundaries of the HEC are marked with yellow markers. The red markers are indications of either single structures or

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[131] *See* South Dakota Air Quality Permit Application Form, Title V (Part 70) Operating Permit, General Information Form and Certification of Applicant Form, SDEForm - 0471 V2, Item #D, p. 2 of 6

[132] RTP Environmental Associates, *Air Dispersion Modeling and Class II Visibility Analysis for the Proposed HEC in Union County, South Dakota* (Oct. 2007).

[133] The Application, at 2, Section 1.2.

[134] None of the locations showing the red marked neighborhood receptors have been "ground-truthed" to identify the likely presence of people who would be odor receptors.

clusters of structures that are probably farmsteads within a close distance to the prospective HEC fence-line.

D. The Application's Failure To Provide The Proper Environmental Acceptability Analysis Of Odorous Emissions And Their Prospective Neighborhood Impacts, And DENR's Failure To Make Required Inquiries, Findings And Information Demands Of The Applicant Render The Application Non-Approvable

Because the Application and DENR's Statement of Basis both fail to properly consider odor emission impacts from the subject facility on the HEC site neighbors in violation of South Dakota statutes, Commentors assert that DENR must deny the Application. Any future submission of additional information from the Applicant, or other supplemented application material on the matter of odorous emissions and their neighborhood impact, must be only considered in the context of an amended draft permit publication decision with a new public hearing and public comment period. Submission of such supplementary material during a future contested case hearing must not be considered as an acceptable final disposition of this disputed matter in the absence of a new public hearing (not a formal contested format) and public comment period.

When faced with a facility of a nature, scope and source category that poses risks of excessive odor air pollution to an adjacent community, a failure by DENR through inaction to conduct a complete inquiry into the emissions of odors and the effects of such odors outside the fenceline of the facility, and the failure to require a facility to submit a demonstration of environmental acceptability of their emissions that can cause odors, means DENR has abused any discretion it has in addressing odor emissions and impacts.

XI. The Application Does Not Provide Sufficient Information On Electric Interconnect To Determine Applicable New Source Performance Standards ("NSPS")

Information provided in the Application is insufficient to determine if the refinery will have electric interconnect with the grid and what will be done with excess electrical power generated. If experts do not know what will be done with the electrical power generated (i.e., whether it will be sold or not), experts cannot determine if the NSPS Subpart D applies to the IGCC plant or not, and thus cannot determine if proper standards have been implemented. Because Hyperion makes no express claim that it will sell any excess electrical power it generates, it is imperative that DENR include a permit condition in the PSD permit prohibiting Hyperion from selling any electrical power generated.

XII. The Application Fails To Meet CAA §112 Requirements For Characterizing And Controlling HAPs

A. The Application Fails To Fully Characterize Emissions Of HAPs From The Facility

The Applicant provides no information regarding additional emissions units whose HAPs emissions must be considered for purposes of characterizing emissions. For example, the Applicant provides no information on product pipeline emissions units (pumping stations, gasoline bulk terminals) which may be part of the same stationary source due to ownership and dependence relationships, among other factors. The Applicant does not provide the percentage of the crude in the feeder pipelines that will be processed at the facility; nor does the Application characterize any emissions of HAPs from flares other than from flare pilot gas combustion.

Further, the Applicant provided no information as to mercury emissions from mercury in crude, petroleum coke and coal from both refinery process units and the IGCC. The application did not provide the numerical total of individual stack mercury emissions or the numerical total of annual mercury emissions in its soils and depositions report, nor did it provide any information on the break-down of mercury emissions by type (elemental mercury, oxidized mercury, particle-bound mercury and organo-mercury compounds).

Next, the Applicant did not include the information necessary to determine the emissions of other (non-mercury) toxic metal HAPs. The application contains no detailed info on emissions of numerous HAPs, including but not limited to benzene, xylene, phenol, cyclohexane, methanol, aldehydes, ethylene, propylene, and trimethlbenzene.

Finally, the Applicant provided no maximum short-term emissions rates (1 hour, 3 hour & 24 hour) for non-continuous, intermittent emission sources such as flares. Such short term emissions rates must be included for modeling purposes.

B. The Application Incorrectly Characterizes Emissions Of HAPs From Flares

The assumption that the Applicant and DENR make that all flaring systems, including conventional elevated steam-assisted refinery flares, always achieve 98+% control efficiency for organic HAPs is improper. Numerous factors can impact the control efficiency of flares, and neither the Applicant nor DENR appear to have taken those factors into account in determining flare control efficiency and correlated flare emissions.

For example, combustion efficiency of conventional flares can be adversely affected by an excessively high or low tip gas exit velocity, increasing cross-wind interferences, low gas BTU content, inadequate or excessive steam assist flows and gas content molecular weight. Available research indicates that expected control efficiencies of conventional open air assisted flare can drop considerably below 98% control.[135] [136]

[135] *See* Leahey, Preson, and Strosher; *supra* note 41.

[136] *See* Blackwood, *supra* note 42.

C. The Application Does Not Provide Sufficient Information To Verify If The Applicant's HAP Emissions Characterizations Are Correct

1. *The Application Does Not Provide Sufficiently Detailed Information About The Design And Configuration Of The Wastewater Sewage And Transport System To Verify HAPs Emissions From That Emissions Source*

Without this information, neither the state nor the public commentors can evaluate if the closed vent system to control HAP emissions from wastewater treatment units will also control HAP emissions from the facility wastewater sewer system (i.e, benzene, toluene, and xylene). In addition, there is no information to determine if the collection system operates under a negative pressure to capture and convey all materials to its destination.

2. *The Application Provides No Information To Support Its Determination Of HAP Emissions From The Wastewater Treatment Plant And Petroleum Liquids Storage Tanks*

The Applicant relied on WATER9 model estimations of wastewater treatment plant emissions and on TANKS model estimations on the petroleum liquids storage tanks, but did not provide any WATER9 or TANKS model runs, nor did it provide any of the physical assumption information inputted into those predictor models. As such, neither DENR nor the experts can verify if wastewater treatment plant HAP emissions or HAP emissions from petroleum liquids storage tanks were correctly calculated, nor if total emissions of the facility wide emitted pollutants were correctly calculated.

D. The Application's Case-By-Case MACT Analysis Is Flawed

Because the MACT standard for refinery heaters was vacated in 2007, section 112(j) of the Clean Air Act requires that a case-by-case MACT determination be made for the source category for each HAP. However, the Applicant did not consider multiple HAPs in its case-by-case MACT analysis, including mercury, non-mercury metals, organic HAPs, acid gases, dioxins, and radionuclides. Further, the Applicant used improper surrogates in determining MACT. Finally, the Applicant did not consider start-up, shutdown and malfunction operating scenarios is making its case-by-case MACT determination. For all these reasons, the Applicant's MACT determination is unenforceable.

XIII. The Application Does Not Provide Adequate Information To Verify Its Health Risk Assessment

A. Input And Output Files Of The HEM-3 Model Used In The Health Risk Assessment Are Missing

The HEC will emit several toxic chemicals that are known to be carcinogens. A screening level analysis has been performed by Environmental Resources Management in April 2008.[137]

[137] *See* Environmental Resources Management, *Screening-Level Health Risk Assessment for Hyperion Energy Center* (Apr. 23, 2008), available at

This screening analysis used the Human Exposure Model-3 (HEM-3) that was developed by the US EPA. However, the input and output files for the HEM-3 model are not available for review. These input and output files should be made available for review and comment.

B. Emissions Calculations And Emissions Characterizations Of All Toxicant Emissions, Such As Arsenic, Cadmium And Mercury, Are Not Included

The model HEM-3 used in the screening analysis requires emissions rates of toxic air contaminants as inputs. Since the HEM-3 input and output files are not available, modeled toxics and their emissions remain unknown. Furthermore, the Application has not documented the methodologies and assumptions used in emissions calculations and emissions estimates for several toxics such as arsenic, cadmium and mercury. Without this information, toxic emissions can not be verified and, hence, emissions characterization of HAPs remains incomplete.

XIV. Monitoring Requirements Are Inadequate

The Draft Permit contains no (or inadequate) monitoring, recordkeeping and reporting requirements to allow DENR to determine if the facility is in continuous compliance with the emissions limitations in the Draft Permit. Further, due to the lack of adequate monitoring, recordkeeping and reporting requirements, those emissions limitations are not "practically enforceable."

> "...the NSR Manual provides that a PSD permit must, among other things, provide for adequate reporting and recordkeeping so that the permitting agency can determine the compliance status of the source. NSR Manual at B.56; Petition at 21; see also In re Shell Offshore, Inc., OCS Appeal Nos. 07-01 & 07-02, slip op. at 52 n.54 (EAB Sept. 14, 2007), 13 E.A.D. at ___ ("In addition to requiring conditions and limitations [that are] directly enforceable by regulators at both the federal and state level (see 40 C.F.R. § 52.21(b)(17)), the term "federal enforceability" has been interpreted as requiring practical enforceability as well. That is, the permit must include conditions allowing the applicable enforcement authority to show continual compliance (or non-compliance) such as adequate testing, monitoring, and record keeping requirements.")[138]

This is particularly true for systems such as for the flare system. The Environmental Appeals Board considered the importance of such monitoring on systems designed to accommodate upset emissions. They concluded it was essential to have either monitoring parameters or an on-the-record determination pointing to technical or economical limitations on the Application of measurement methodology to such systems during SSM difficulties.

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http://www.state.sd.us/DENR/Hyperion/Air/20080423HyperionEnergyCenterScreeningLevelRiskAssessment.pdf.

[138] *In re: ConocoPhillips Co.*, PSD Appeal No. 07-02, at 38-9 (E.A.B. June 2, 2008).

> Absent an on-the-record determination pointing to technical or economical limitations on the Application of measurement methodology to Indeck's CFB Boilers sufficient to invoke section 52.21(b)(12), or some other reference point for allowing non-numeric BACT limits for design and operational SSM difficulties, we cannot conclude that IEPA legitimately substituted numeric limits with work and operational practices. Under these circumstances we conclude that the permit provisions substituting work and operational practices for BACT numeric limits must be remanded to IEPA. If, on remand, IEPA determines that emissions cannot be measured during SSM events, then IEPA needs to make an on-the-record determination to that effect and also determine that the work and operational practices are equivalent to BACT. If IEPA determines that Indeck's infeasibility is caused by other types of technical limitations, and intends to retain the provisions that exempt short-term emissions from compliance with BACT, IEPA must demonstrate how the permit conditions comport with the applicable regulations, as interpreted by the EPA guidance discussed above, show that short-term ambient standards are protected, and demonstrate that the permit conditions are in compliance with NAAQS and PSD increments provisions. Moreover, IEPA must specify and carefully circumscribe in the permit the conditions under which Indeck would be authorized to exceed these otherwise applicable emission limits. (Footnotes omitted)[139]

Neither DENR nor the Applicant has made the case that technical or economic limitations prohibit the use of numeric limitations for BACT limits on the flare system during normal operations or during SSM. Even if DENR had made such a determination (which it has not), they would need to determine that the work and operational practices proposed by the Applicant constitute an equivalent to BACT. The Applicant has not submitted and DENR has not evaluated any SSM plan for the flare system, therefore it cannot make a determination that the non-existent SSM plan is equivalent to BACT. Moreover, the SSM plan, whenever it is submitted, is not required to be included as an enforceable term and condition of the permit, but simply "approved" by DENR and maintained on-site.

Where, as here, most of the emissions limits are expressed on an hourly basis the monitoring and record keeping requirements needed in the permit to make the condition practically enforceable must comport to that time period. The United States Circuit Court of Appeals for the District of Columbia cited this issue as one of the problems that led them to vacate EPA's monitoring rules.

> For example, suppose there is a standard that limits emission from a given stationary source to X units of pollutant per day. Suppose also that the standard requires annual monitoring. Where annual testing cannot assure compliance with a daily emission limit, may the permitting authority supplement the monitoring requirement "to assure compliance with the

[139] *Indeck-Elwood, LLC*, PSD Appeal No. 03-04, at 75-6 (E.A.B. Sept. 27, 2006).

permit terms and conditions," as the Act commands? 42 U.S.C. § 7661c(c).[140]

As specified below, the Draft Permit contains no (or inadequate) monitoring provisions to allow determinations of continuous compliance with the applicable permit emissions limitations and requirements, rendering those limitation not practically enforceable.

A. The Draft Permit Fails To Include Appropriate Compliance Assurance Monitoring, Recordkeeping And Reporting To Address The Sulfur Recovery Unit Thermal Oxidizer BACT Sulfur Dioxide Emission Limitation On A Process Sulfur Input Basis

The Draft Permit contains a mass rate emission limitation of 114.2 pounds of sulfur dioxide per hour, but this limit is applied as a bubble over 4 operating SRU-Thermal Oxidizer process trains. Such a bubble emission limitation is not capable of ensuring that each specific SRU-Thermal Oxidizer process train is maintain a BACT level of sulfur dioxide emission control efficacy. Sulfur dioxide continuous emission monitoring can be used to address compliance assurance monitoring on this bubble limit, provided the owner-operator provides an appropriately formatted reporting document format.

However, each SRU is subject to an individual process throughput SO_2 emission rate of 0.056 pounds of sulfur dioxide per long ton of sulfur "loaded to the system" and is intended as a process rate-based BACT SO_2 emission limitation. Commentors presume "loaded to the system" to mean the amount of sulfur that is input to the specific SRU-Thermal Oxidizer process train.

The Draft Permit fails to include any federally enforceable continuous parameter monitoring requirements addressing the sulfur input flux to each of the 6 SRU-Thermal Oxidizer process trains. There are no compliance assurance monitoring, recordkeeping and reporting requirements that will verify facility compliance with the 0.056 pound of sulfur dioxide per long ton of sulfur SRU input emission limitation.

The Draft Permit must not issue without resolving this compliance monitoring issue. On reconsideration, new requirements for the nature of SRU input parameter monitoring must be specified, as well as to determine the data integration responsibilities of the owner/operator to produce reports which can determine compliance with the subject SO_2 BACT limit.

B. The Draft Permit Should Require Applicant To Install Stack Gas Flow Monitoring Capability On All Of The SRU Thermal Oxidizer Vent Stacks

Because of SRU-Thermal Oxidizer process variability and uncertainties and expected temperature variability of Thermal Oxidizer flue gas and its effects on actual flue gas volumetric discharge rates, there should be no reliance on calculated F-factors to determine flue gas flow to BTU input relationships. Accurate determination of flue gas flow rate is essential to ensuring proper data integration from flue gas pollutant concentrations indicated by continuous emission

[140] *Sierra Club v. EPA*, 536 F.3d 673, 675 (D.C. Cir. 2008).

monitoring equipment for purpose of mass emission rates limit compliance.

The Draft Permit should be amended to require installation of continuous flue gas volumetric flow monitoring in all SRU Thermal Oxidizer stacks to properly support continuous compliance assurance monitoring for all regulated pollutant emissions.

C. The Draft Permit Fails To Include Detail On Flare Monitoring

As noted earlier, flare emissions are not properly characterized. Since emissions from the types of flares proposed are not easily characterized directly, such as via source tests or stack tests, flare emissions monitoring generally relies on a combination of monitoring gas feed quantities and composition to the flare as well as indirect monitoring of emissions impacts from flares such as via remote monitoring. None of this is addressed in the Application in any level of detail that would result in appropriate enforceable conditions. As noted earlier as well, a Flare Monitoring Plan with sufficient detail is not provided.

D. The Draft Permit Fails To Include Detail On Fenceline Monitoring

Although fenceline monitoring is mentioned in the Application, no details are provided. The spatial coverage of such monitoring, the methods that will be used, the frequency of data collection or analysis, the type of analysis (in-situ or ex-situ), the pollutants to be monitored, etc., are not discussed in detail. Also not discussed are the steps that will be taken for data analysis, data validation, data comparison, the metrics that will be used for data comparison, and the steps that will be taken if the data comparisons result in failures of such monitoring.

E. The Draft Permit Fails To Include Detail On Leak Detection And Repair ("LDAR")

LDAR programs are required under several regulations in order to monitor fugitive emissions from sources such as valves, flanges, and pumps. Accurate data collection in this regard requires careful adherence to operating practices and procedures (such as the location and distance of the monitor to a specific source, the wind condition during monitoring, etc.). The application does not specify how LDAR monitoring will be conducted at the refinery, the standard operating procedures that will be followed, the manner in which the data will be validated and housed, and data handling and management aspects. Also not specified are the steps that will be taken to keep fugitive emissions to a minimum. As such, without such detail, it is impossible to determine the level of components that will be deemed to be leaking versus those that are not. This is a critical distinction since significantly more emissions accrue from leakers than non-leakers. Assumptions made in the Application with regards to the ratio of leakers to non-leakers are not supportable based on audits conducted in refineries by EPA and other agencies. Therefore, unless more details on the LDAR program are provided, the assumptions regarding the relatively small number of leakers should be set aside and emissions re-calculated based on actual ratios found in refineries.

F. For Combustion Units Controlled With Selective Catalytic Reduction, Continuous Parameter Monitoring For Ammonia Slip Emissions Should Be Required

Selective catalytic reduction systems feature ammonia injection with catalytic reactions to control nitrogen oxide emissions. However, if more ammonia is injected than is needed to react with the nitrogen oxides in the flue gas, excess ammonia will be emitted.

The Draft Permit should be amended to include requirements for continuous ammonia slip monitoring on all SCR-controlled combustion units.

G. The Draft Permit Should Be Revised To Incorporate Federally Enforceable Requirements For Continuous Oxygen Concentration, Flue Gas Flow Rate Monitoring And Fuel Mix Monitoring For The Five Combustion Turbine-Duct Burner Stacks

Because of the variability of fuels and fuel combinations intended for use in the combustion turbine/duct burner units, the Applicant should be required to install continuous oxygen monitoring and flue gas flow rate monitoring in each flue stack. The Applicant should not be allowed to rely on a pre-determined F-factor for relating flue gas volumetric rates to BTU heat input for data integration purposes with continuous emission monitors.

Monitoring parameters for continuous flue gas flow rate and oxygen concentrations for data integration with CEM monitoring results, along with accompanying EPA performance specifications for quality assurance and quality control on such continuous parameter monitoring, should be placed into the permit as federally enforceable requirements.

Because the determination of which NO_X emission limitation is in effect at any given time depends in the Draft Permit on which gas streams are being combusted, continuous fuel gas flow monitoring requirements for syngas and natural gas to each combustion turbine - duct burner combustion train should be incorporated into the Draft Permit as federally enforceable requirements. Such permit provisions must include performance specifications and reporting requirements to provide quality assurance and quality control.

XV. Enforcement Requirements Are Unclear And Illegal

A. Many Of The Draft Permit Requirements Are Not Practically Enforceable

EPA Guidance on the practical enforceability of PSD permit conditions requires the presence of specific production or operational limitations.

> To appropriately limit potential to emit consistent with the opinion in Louisiana-Pacific, all permits issued pursuant to 40 C.F.R. Sections 51.160, 51.166, 52.21 and 51.165 must contain a production or operational limitation in addition to the emission limitation in cases where the emission limitation does not reflect the maximum emissions of the source operating at full design capacity without pollution control equipment. . . . Production

> and operational limits must be stated as conditions that can be enforced independently of one another.[141]

There are no operating rates described in the Draft Permit for most units. For example, Page 18 Footnote #1 states that for the description of emissions and operating units, "The operating rate is the nominal or manufacturer listed operating rate noted in the PSD application and are descriptive only." If these are not enforceable operating limits, what operating limits are enforceable? What operating conditions were used to calculate emissions for modeling? Many of the permit limits for individual emission units are only rate based (lbs per MMBTU) and have no mass emissions limits (tons per year or pounds per hour).[142]

B. The Draft Permit Conditions Are Inconsistent And Illegal Under The Credible Evidence Rule

The Draft Permit, at Page 19 Credible Evidence, states that "monitoring, testing, and compliance" methods may be used to show a violation. Much of the permit relies on emissions models (TANKS, WATER9, etc.) to calculate emissions. These computer models (which the Applicant relied upon) should also be included as credible evidence methods for demonstrating a violation.

At various locations,[143] the Draft Permit says, "Compliance with the hydrogen chloride limit shall be based on the average of three one-hour test runs based on the performance test procedures and requirements in Chapter 10.0." This implies that other methods of demonstrating a violation are inapplicable and destroys the credible evidence rule. The Draft Permit needs to be revised to allow use of any and all credible evidence to show non-compliance with any permit condition.

C. The Soot Blowing Startup, Shutdown And Malfunction Exclusions Are Illegal

It is axiomatic that BACT conditions cannot be waived during periods of startup, shutdown or malfunction.

> BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown. EPA has issued three guidance documents over the years clearly expressing the Agency's long-standing position that automatic exemptions for excess emissions (i.e., emissions in excess of BACT or other permit limits) during startup and shutdown periods cannot be reconciled with the directives of the CAA...[144]

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[141] U.S. EPA, *Limiting Potential To Emit In New Source Permitting*, at 5-6 (June 13, 1989).

[142] *See* the Draft Permit, at 41, Table 4.4.

[143] *See, e.g,* the Draft Permit, at 57, n. 1.

[144] *In Re: Tallmadge Generating Station*, PSD Appeal No. 02-12, at 10 (E.A.B. May 22, 2003).

The Draft Permit impermissibly excludes such emissions in various location. For Example, Page 35, footnote #1 and many other footnotes of the Draft Permit state, "Unless otherwise noted, compliance with the emission limit is based on a 24-hour rolling average, excluding periods of startup, shutdown, and malfunctions."

DENR has included similar impermissible exclusions for soot blowing. Page 58, Section 9.1, of the permit states, "An exceedence of the opacity limit is not considered a violation during brief periods of soot blowing, startup, shutdown, or malfunction. Malfunction means any sudden and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner." This is in direct conflict with EPA Guidance. "The Agency guidance on this issue states that soot-blowing is a routine operation constituting representative process conditions. Emissions from soot-blowing cannot be discarded as being the result of an upset condition."[145]

Even if such SSM or soot blowing could be excluded from BACT emissions limitations (which they cannot), the Draft Permit fails to contain any emissions limitations, monitoring requirements or reporting requirements applicable to such SSM or soot-blowing conditions. The Draft Permit simply allows these emissions to occur off the books, unrecorded and unreported. This violates the Clean Air Act and EPA's PSD requirements.

As Noted by Judge David Tatel in the September 12, 2008 Oral Argument in *Sierra Club, et al. v. EPA*, (D.C. Circuit, No. 02-1135), "I don't see an exception in the statute for periods of startup, shutdown and malfunction."

D. <u>The Permit Must Include Additional Physical Throughput Or Production Rate Requirements To Limit The Potential To Emit</u>

Courts have ruled that only physical throughput and/or production rate requirements actually have the effect of limiting or defining the potential to emit of a stationary source. The only physical throughput and/or production rate limitation contained in the permit is the requirement not to refine more than 400,000 barrels of crude oil per day in Section 5.1.

Nothing about the refinery crude oil rate per day defines the throughput limits for the IGCC power plant. The IGCC system operational limit in Section 5.2 of the Draft Permit does not limit the potential to emit of the IGCC system. There is no limitation on coal/coke charged to the IGCC power plant that effectively limits the potential to emit of this process unit. The overall crude oil refined per day limit in Section 5.1 does not necessarily limit the short term potential to emit of individual process units within the refinery. Finally, there is no operational limitation on the cooling tower water recirculation rate to limit the potential to emit of the cooling towers.

XVI. <u>Conclusion</u>

For all the above-mentioned reasons, we submit that the Hyperion Energy Center's Draft Prevention of Significant Deterioration Air Quality Preconstruction Permit, issued by DENR on

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[145] U.S. EPA, *Clean Air Act National Stack Testing Guidance*, at 15 (Sept. 30, 2005).

September 11, 2008, is fatally deficient. We respectfully request that DENR decline to issue a final permit at this time.

In addition, given the significant omissions in the Application and Draft Permit discussed above, and pursuant to the public comment provisions in the PSD program, we note that no revised PSD permit should be issued to HEC unless DENR offers the public notice and opportunity for comment on that permit.